EXHIBIT A

Application: 15-05-xxx
(U 39 M)
Exhibit No.: ____________________
Date: May 1, 2015
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY MODEL ASSESSMENT PROCEEDING

PREPARED TESTIMONY

PG&E®

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY MODEL ASSESSMENT PROCEEDING (S-MAP)
PREPARED TESTIMONY

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CHAPTER 1

OVERVIEW AND SUMMARY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
OVERVIEW AND SUMMARY

A. Introduction

In this proceeding, Pacific Gas and Electric Company (PG&E) provides an introduction and overview of its models and methodologies used to prioritize and mitigate safety risks. This proceeding—known as the Safety Model Assessment Proceeding (S-MAP)—is submitted in accordance with Decision 14-12-025 of the California Public Utilities Commission (CPUC or Commission).

1. General Principles Guiding This Filing

PG&E has embraced risk-informed decision-making in its planning and budgeting process and fully supports the Commission's increased focus in this area. In the rapidly developing area of risk assessment and mitigation, utilities will continue to identify areas of improvement for their processes.[1] Similarly, the Commission and stakeholders may need to increase their own technical capabilities for evaluating the risks facing utilities and the proposed strategies for mitigating those risks. All participants in this new dialogue will also need to ensure that they share a common understanding of terms. If not, misunderstandings likely will ensue.

Utilities, the Commission and stakeholders are in this together. Accordingly, PG&E has approached this proceeding with the following general principles in mind.

a. PG&E Welcomes a Sharing of Risk Management Practices

PG&E welcomes a sharing of risk management practices—both formally and informally—among stakeholders in California. In addition to this proceeding, PG&E has reached out to other participants in the State and around the country to share lessons learned. This sharing will continue beyond the issues contemplated for this first S-MAP.

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1 While PG&E provides its principal risk models and methodologies in this filing, PG&E expects to develop additional tools, models and standards as its risk management process matures.

b. Cooperation Among the Parties Will Advance the Industry

In the developing area of utility risk management, cooperation among the parties will best serve to advance the industry's efforts. All of the S-MAP participants have a common interest in advancing the art and science of utility risk management. To that end, PG&E aims to promote a cooperative atmosphere in this proceeding. The topics to be covered in the S-MAP lend themselves well to workshops and multimedia demonstrations, not the formality of evidentiary hearings.

c. PG&E Has Focused on the Management of Safety Risks

PG&E expects that the S-MAP—and future Risk Assessment and Mitigation Proceedings' (RAMP) and General Rate Cases' (GRC) discussion of risks—will focus primarily on key safety risks. PG&E manages other important risks, such as environmental and financial risks, although PG&E expects that such risks will not be the focus in the S-MAP.

d. Uniform Standards Are Appropriate in Some Areas and Inadvisable in Others

In the decision, the CPUC questions whether or not "uniform or common standards" is a goal that should be pursued.[2] Some areas lend themselves well to common standards. Others do not. The former category could include, for example, the development of a risk lexicon; the application of a common framework—ISO 31000; and the use of a common process as described in the Cycla Corporation's (Cycla) May 16, 2013 report in PG&E's 2014 GRC.[3] The latter category includes algorithms and programs for addressing risk, which are likely to differ from company-to-company, based on the characteristics of that company's assets, environment and customers.

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2 D.14-12-025, mimeo, p. 30 ("The S-MAP decision can also address whether uniform or common standards must be used by the energy utilities in the next S-MAP filings, or direct the energy utilities to pursue the issue further.").

3 Cycla's 10-step process is presented in Section B.1. below.

e. The S-MAP Should Not Be Assumed to Be Open-Ended

The decision states that the S-MAP will take place "every three years…unless directed otherwise by the Commission."[4] At this juncture, it would be inappropriate to assume that the number of S-MAPs will be open-ended. One must be cognizant of the impacts of new proceedings. Such proceedings translate to higher administrative costs for the utilities and, of course, stress the limited resources of the Commission and stakeholders.

In addition to our concerns about the number of S-MAPs going forward, PG&E is equally concerned that the S-MAPs are resolved timely. The Commission's Decision 14-12-025 requires that the S-MAP decision be issued prior to the first RAMP filing in order to improve the incorporation of risk and safety into utility rate cases. Accordingly, PG&E would like to see this proceeding move forward efficiently and conclude promptly.

2. Organization of This Testimony

PG&E's testimony is comprised of five chapters. The first two chapters address enterprisewide models. In Chapter 2, PG&E presents its Enterprise and Operational Risk Management Program (EORM) and Risk Evaluation Tool (RET), which are used to identify and rank enterprisewide and operational risks. In Chapter 3, PG&E presents its risk-informed budget allocation (RIBA) process, which is used to prioritize work in the core lines of business according to risk scores. Thereafter, PG&E presents line of business-specific approaches to risk management. Chapter 4 presents PG&E's approach in Electric Operations and Nuclear Power Generation. Chapter 5 presents PG&E's approach in Gas Operations. Chapter 6 presents a risk lexicon developed in conjunction with Southern California Edison Company (SCE) and the Sempra utilities (Sempra). The definitions in Chapter 6 are thus jointly sponsored by SCE, Sempra and PG&E.

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[4] D.14-12-025, mimeo, p. 55 (Ordering Paragraph 5).

The testimony takes the following structure:

TABLE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
STRUCTURE OF TESTIMONY

Chapter	Title	Witness
1	Overview and Summary	S. Sharp
2	Companywide Models and Approaches for Assessing Risk	J. Markland
3	Companywide Models and Approaches to Risk Informed Budget Allocation	J. Martin
4	Electric Operations and Nuclear Power Generation	E. Back and C. Harbor
5	Gas Operations	C. Chapman
6	Risk Lexicon	J. Markland
Appendix A	Statements of Qualifications	All

3. Relationship of This Filing to PG&E's Upcoming GRC

This S-MAP is not a formal precursor to PG&E's 2017 GRC. (PG&E will file its 2017 GRC on September 1, 2015.) PG&E's 2020 GRC will be the first PG&E GRC to incorporate the results of this S-MAP and to have a formal RAMP. PG&E expects to submit the RAMP for the 2020 GRC in October 2017.

Although the new risk proceedings instituted through Decision 14-12-025 will not be fully incorporated until PG&E's 2020 GRC, PG&E will follow the spirit of Decision 14-12-025 in the preparation of its 2017 case. To that end, PG&E will provide more extensive testimony on safety and risk and PG&E will explain how its forecast relates to safety and risk priorities. The 2017 GRC testimony will also follow the Commission's directive from PG&E's 2014 GRC, namely:

- PG&E will provide additional testimony on its Integrated Planning Process; affirmatively showing that risk management through integrated planning forms the foundation of the system safety and compliance projects and programs forecast in its 2017 GRC.
- PG&E will prioritize projects and programs in the 2017 GRC by using risk-based criteria and will describe how the projects and programs it is

forecasting mitigate the system safety risks listed on PG&E's Risk Register.

- PG&E will provide enhanced testimony on its overall risk program from its Chief Risk Officer as well as line of business-specific risk testimony from the risk or asset management leads from Electric Operations, Energy Supply and Gas Operations.[5]

4. Risk and PG&E's Integrated Planning Process

As described above, PG&E will provide additional testimony on its Integrated Planning Process in its 2017 GRC. The annual Integrated Planning Process consists of four primary steps.[6] The first step is establishing "Executive Guidance," where PG&E sets forth its goals for the next five years. The second step is Session D—developed from January through April—which is used to review and discuss progress made to manage PG&E's top compliance, enterprise and operational risks. The third step in the process is Session 1—developed from April through July—which outlines PG&E's 5-year Operating Plan, including goals and strategies. The fourth step is Session 2—developed from August through October—which sets forth PG&E's 2-year execution plan. The Integrated Planning Process is an iterative cycle and adjustments can be made to PG&E's plan to incorporate emerging information. For example, while Session D reviews are completed in April, senior management—through their risk and compliance committees—regularly review the status of risks and mitigation activities. Additionally, the Risk Policy Committee, which is chaired by the Chief Executive Officer, conducts a "mid-cycle check in" where the Committee reviews progress relative to PG&E's risk profile and implementation of the EORM program. The leadership team will collectively make a decision to address newly identified gaps in PG&E's work plan if warranted.

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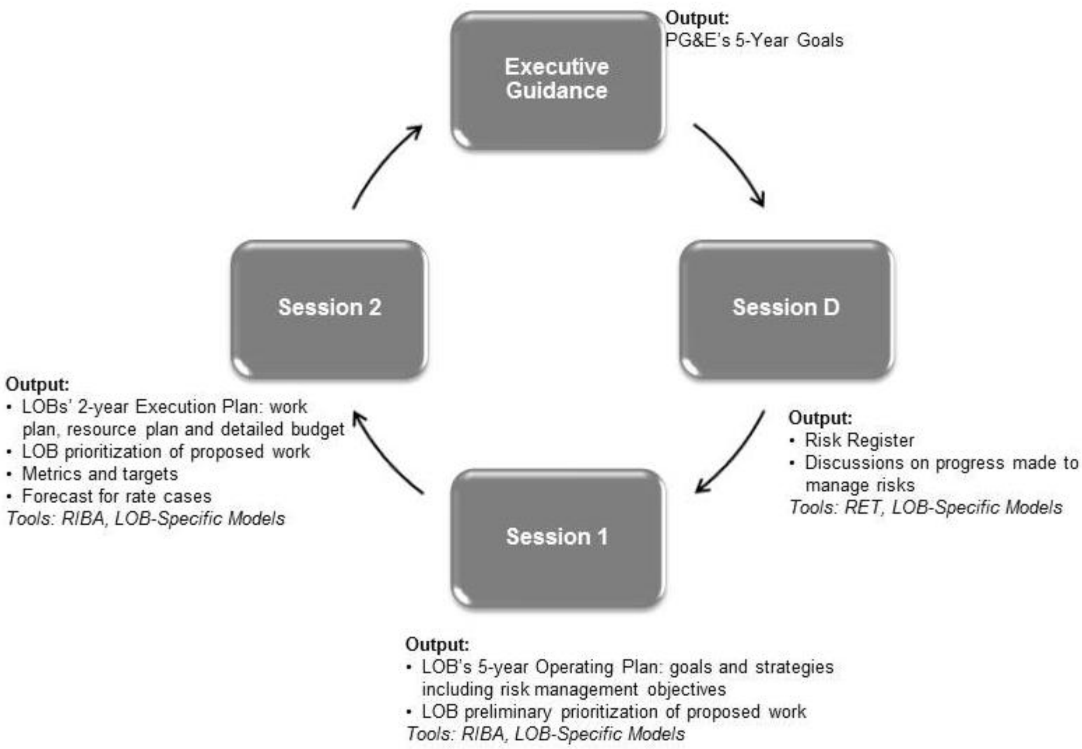
5 D.14-08-032, mimeo, p. 12.

6 PG&E's Integrated Planning Process also contains an additional step, Session C, for the Company's senior leadership development and succession planning.

Figure 1-1 below illustrates the Integrated Planning Process cycle and the key outputs of the process and the tools used in each step of the process.

FIGURE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
INTEGRATED PLANNING PROCESS



B. Approach to This S-MAP

PG&E has approached this S-MAP in accordance with the expectations of the Refined Straw Proposal, which envisioned:

> the initial S-MAP [would] 'serve primarily an informational and education function – acquainting parties with the utilities' models – and provide utilities an opportunity to hear reactions from Commission staff and parties and modify their models as they deem appropriate in response to Staff/parties' concerns and recommendations.[7]

PG&E understands that the Commission's expectations and scope of the S-MAP will change over time. Not everything can be accomplished in the first S-MAP.[8]

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[7] D.14-12-025, mimeo, pp. 22-23.

[8] D.14-12-025, mimeo, p. 26.

While the Commission considers the longer term goal of evaluating "uniform and common standards," the Commission raised three topics for consideration.[9] First is "whether the S-MAP should be a recurring proceeding, and if so, how often should that be."[10] Second is whether workshops or an S-MAP working group should determine whether common standards can be developed.[11] Third is whether Commission staff and other parties have sufficient expertise to understand and analyze the S-MAP methods and methodologies.[12]

PG&E addresses these three topics below.

1. Content of This S-MAP and Future Filings

The Commission has concluded that S-MAPs "should be held at least two times, at an interval of three years."[13] And, "[i]n the second proceeding, the Commission can decide whether the S-MAP proceedings should continue in the future or be terminated."[14]

PG&E has set forth a framework in Table 1-2 for the content of two S-MAPs. This framework is tied to Cycla's 10-step process reflecting the elements of a risk-informed resource allocation process. Cycla presented this 10-step process in PG&E's 2014 GRC. As shown in Table 1-2, PG&E proposes addressing five of the ten steps in this first S-MAP and deferring two steps to the second S-MAP. (The remaining three steps are already addressed in the GRC process.) PG&E would defer those steps (1) pertaining to evaluating risk reduction; and (2) monitoring the effectiveness of risk control measures. As explained more fully in Chapter 2, Sections D.2.a. and D.3., quantifying risk reduction is in a particularly early state of development. S-MAP discussions in this area would benefit from additional time to mature.

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9 D.14-12-025, mimeo, p. 26.

10 D.14-12-025, mimeo, p. 26.

11 D.14-12-025, mimeo, p. 26.

12 D.14-12-025, mimeo, pp. 26-27.

13 D.14-12-025, mimeo, p. 27.

14 D.14-12-025, mimeo, p. 27.

TABLE 1-2
PACIFIC GAS AND ELECTRIC COMPANY
CYCLA'S 10-STEP RISK PROCESS

Step	Cycla Process	Model/Method/Process	Proceeding Where Process Step Should Be Addressed
1	Identify Threats	EORM Program Session D – Risk RET	This First S-MAP (Chapters 2, 4, 5)
2	Characterize Sources of Risk	EORM Program Session D – Risk RET	This First S-MAP (Chapters 2, 4, 5)
3	Identify Candidate Risk Control Measures (RCM)	EORM Program Session D – Risk Session 1 – Strategy Session 2 – Execution Plan RIBA	This First S-MAP (Chapters 2, 3, 4, 5)
4	Evaluate the Anticipated Risk Reduction for Identified RCM	EORM Program Session D – Risk	Second S-MAP
5	Determine Resource Requirements for Identified RCMs	EORM Program Session 1 – Strategy Session 2 – Execution Plan RIBA	This First S-MAP (Chapters 3, 4, 5)
6	Select RCMs Considering Resource Requirements and Anticipated Risk Reduction	EORM Program Session 1 – Strategy Session 2 – Execution Plan RIBA	This First S-MAP (Chapters 3, 4, 5)
7	Determine Total Resource Requirement for Selected RCMs	EORM Program Session 1 – Strategy Session 2 – Execution Plan RIBA	General Rate Case
8	Adjust the Set of RCMs to be presented in GRC Considering Resource Constraints	EORM Program Session 1 – Strategy Session 2 – Execution Plan RIBA	General Rate Case
9	Adjust RCMs for Implementation following CPUC decision on Allowed Resources	EORM Program Session 2 – Execution Plan RIBA	General Rate Case
10	Monitor the Effectiveness of RCMs	EORM Program Session D – Risk	Second S-MAP

2. The Role of Workshops

On the topic of how to involve workshops in the S-MAP, the Commission concluded that they "could be useful toward reaching a consensus about uniform or common standards. These additional workshops or working

groups are something the parties and the ALJ in the S-MAP proceedings should consider."[15]

PG&E agrees that workshops would be useful. Indeed, PG&E believes that workshops are likely to be more fruitful than evidentiary hearings for the topics under consideration. These topics are technical and include calculations, algorithms, and complex concepts. These issues are best, and most easily, explored through workshop discussions, not formal cross-examination.

For these reasons, PG&E proposes a series of workshops in lieu of evidentiary hearings. These workshops should cover the following topics:

- Risk Lexicon – this session would have the parties work together to develop a risk lexicon based upon that jointly put forward by the utilities. PG&E envisions that this lexicon would be an educational resource, maintained by the Commission, that could be used by the Commission, utilities and stakeholders.
- Benchmarking of Utility Risk Processes – this session would examine the current state of utility risk management outside of California.
- Presentation of Utility Risk Models – this session would allow for more in-depth presentations and discussions concerning the utility risk models. This session could include live demonstrations of the models.
- Data Issues – this session would address data issues such as the relative value of qualitative and quantitative data, as well as the use of predictive vs. lagging indicators.
- Areas for Common Standards – this session would address the Commission's interest in exploring whether common standards would be useful and have the parties work together to identify possible areas for such standards.

If the Commission wishes to develop a record concerning these workshops, PG&E would support videotaping/webcasting the workshops, working with staff to develop reports, or otherwise formalizing the content of the workshops.

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15 D.14-12-025, mimeo, p. 28.

3. Commission and Stakeholder Expertise

PG&E is not in the best position to assess whether or not the Commission and stakeholders currently have the requisite expertise to review the utility models and methodologies. In the past, both Commission staff and intervenors have expressed concerns about the level of their expertise. To the extent that additional expertise is required, PG&E supports the Commission and parties obtaining such expertise through internal staff (in the long-term) or external consultants (in the short-term). The more expertise at the table, the more productive this proceeding is likely to be. In this regard, PG&E supported the hiring of experts by the Safety and Enforcement Division during PG&E's 2014 GRC.

C. Relief Requested

PG&E understands the main purpose of this first S-MAP proceeding to be an informational and educational one.[16] Accordingly, the formal relief requested by PG&E is relatively limited.

PG&E seeks:

- The Commission's development of a risk lexicon based on the definitions proposed herein.
- The Commission's guidance for the content of the next S-MAP. PG&E recommends that the next S-MAP focus on:
  - A methodology for evaluating anticipated risk reduction and monitoring the effectiveness of identified risk control measures.
  - The evaluation of common standards in areas where the Commission in this S-MAP deems such standards to be advisable.

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[16] D.14-12-025, mimeo, pp. 22-23.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

COMPANYWIDE MODELS AND APPROACHES FOR ASSESSING RISK

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COMPANYWIDE MODELS AND APPROACHES FOR ASSESSING RISK

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
COMPANYWIDE MODELS AND APPROACHES FOR ASSESSING RISK

A. Introduction

Pacific Gas and Electric Company's (PG&E) goal is to deliver safe, reliable and affordable gas and electric service to the millions of homes and businesses that depend on us. Numerous operational risks affect the provision of gas and electric service, including natural hazards such as seismic activity and wildfires. Although risk cannot be eliminated, PG&E is committed to managing these risks and taking all reasonable measures to provide gas and electric service to our customers in a way that protects the safety of the public and our employees.

This chapter describes the progress PG&E has made in implementing an industry-leading Enterprise and Operational Risk Management (EORM) Program since 2011. It also includes a description of the EORM process, including an in-depth look at PG&E's Risk Evaluation Tool (RET) that is used to assess and rank risks across PG&E. This chapter concludes with an assessment of where PG&E is compared to other companies in the industry and a look at current challenges and future areas for improvement.

B. EORM Program Overview

PG&E's program is based on International Standards Organization-31000 principles and is squarely focused on providing an in-depth analysis of the enterprise and operational risks inherent in our business, the current state of controls around those risks, and the options for mitigating them further.

PG&E's EORM Program includes a robust governance structure, standard criteria and tools for assessing Company risks, dedicated resources within the Chief Risk Officer's (CRO) organization and within all PG&E's lines of business (LOB), defined mechanisms for cross-company collaboration, active management of LOB-specific risk registers, and integration with PG&E's Integrated Planning Process.

1. People and Processes

a. Personnel

PG&E's Enterprise and Operational Risk Management Department resides in the Chief Risk Officer Organization and reports to the CRO. The CRO reports to PG&E's Chief Financial Officer. Led by the Director of EORM and Insurance, the EORM Department:

- Develops, implements and maintains enterprise-wide risk management guidance for the business.
- Partners with, and coaches, LOB risk managers and other key individuals to help identify, evaluate and mitigate risks.
- Provides process support, advice, and recommendations to ensure effective risk management within the business.
- Evaluates quality and tracks the implementation of mitigation activities.
- Leads the risk components (Session D as previously described in Chapter 1) of PG&E's Integrated Planning Process.

Each LOB also employs dedicated staff to implement the EORM Program standards and procedures within their own LOB. These employees are responsible for:

- Managing the LOB's risk register.
- Leading risk identification and evaluation workshops within the LOB.
- Working with subject matter experts (SME) to develop a risk response strategy, including alternatives analysis.
- Ensuring risk mitigation activities are implemented according to an agreed upon schedule.
- Developing metrics to track progress and assess the effectiveness of mitigations.

b. Committees

Committees serve an important oversight role within the EORM Program. At the Board of Directors, PG&E's audit committee is responsible for overseeing the EORM Program. Oversight of specific enterprise-level risks are addressed by the various Board committees, primarily the Nuclear, Operations and Safety Committee. Board

committees complete in-depth reviews of each enterprise-level risk at least once every 12 months.

PG&E's Risk Policy Committee, comprised of PG&E's most senior officers, annually reviews progress made by each LOB in implementing the EORM Program and how PG&E's risk profile may be changing over time.

In addition, each LOB has its own Risk and Compliance Committee. Chaired by the most senior officer of the LOB, these Risk and Compliance Committees typically meet at least four times per year and are responsible for overseeing EORM activities within their LOB, including reviews of risk assessments and progress made in implementing mitigation activities.

c. Monitoring and Metrics

Once PG&E has identified and evaluated risks, determined which ones must be mitigated further, and secured the resources to do so, PG&E's standards require LOBs to monitor progress. Mitigations are tracked and reported at regular LOB Risk and Compliance Committee meetings and, on a quarterly basis, mitigation progress is discussed at PG&E's Business Plan Review meeting chaired by the President. If mitigation plans are delayed, an action plan is created.

PG&E's EORM standard includes identification of metrics to help evaluate the results of mitigation plans and to detect if conditions are changing in a way that would trigger a re-evaluation of the risk. These metrics can help determine if the risk reduction plan has been successful, or if the LOB needs to adjust its course. In many cases, LOBs have developed and are monitoring these metrics. In other cases, these metrics are under development or are being refined.

Lastly, the EORM team oversees the implementation of risk response activities, and the LOBs' implementation of the EORM process to ensure that standards are adhered to and progress is being made in implementing the right mitigations to reduce the risk.

2. History of the Program

After establishing the standards and procedures for implementing EORM in 2011, PG&E's Risk and Audit Organization focused on implementing PG&E's vision of data-driven, risk-based decision making to support safe, reliable, and affordable electric and gas service that is integrated into PG&E's planning process and becomes the foundation for our regulatory rate cases.

In 2012, each LOB began working with the standards and procedures issued by the Chief Risk and Audit Officer and began to build LOB-specific risk registers. Through this work, PG&E began to use a common risk language and developed a deeper understanding of the risks PG&E faces and the drivers behind them.

The development of formal risk registers began in 2012, although at this time, the risk identification effort took place as a stand-alone process.

3. Integration With PG&E's Planning Processes

Once risk registers were established in each LOB, the focus shifted to integrating risk into how PG&E plans and prioritizes work. In 2013, PG&E held its first annual Session D, which is a senior management discussion of the top risks and compliance requirements facing PG&E. Session D—which began as a one-day meeting and has now expanded to two days—remains an annual event where the senior officers spend time discussing how top risks are being managed, where collaboration across LOBs is required, and where additional resources may be needed.

As one of the first steps in PG&E's Integrated Planning Process, Session D helps to develop an understanding of the top risks and compliance requirements and that knowledge informs PG&E's strategy and execution plans. As mentioned in Chapter 1, these strategy and execution plans are called Session 1 and Session 2, respectively, and are informed by Session D.

C. The Risk Evaluation Tool

1. Purpose

Central to PG&E's EORM Program was the development and use of PG&E's RET. The EORM team created RET as a means of facilitating an

apples-to-apples comparison of risks across LOBs, and to ensure that the risks that rise to the top of the priority list are those that have the largest potential of preventing PG&E from achieving its objective of providing safe, reliable, and affordable service to its customers. RET is used to establish a risk score for each risk and to establish a relative priority for discussion and management purposes. The RET score is a product of the potential impact and the frequency of a risk event. Each risk event is further described as a SME-proposed Probable Worst Case (P95)[1] scenario.

2. Evolution of the Tool

The initial RET Model (referred to as RET1) was modified in 2013 to produce RET2, and again in 2014 to create what is now referred to as RET2.1. The RET1 Model used a 3 × 3 matrix of high, medium, and low impact vs. high, medium, and low frequency. Additionally, the RET1 algorithm was linear in nature and placed more emphasis on frequency than impact. Given concerns about the inability to correctly predict frequency, there was less confidence in the RET1 output. RET1 also resulted in less-than-desired differentiation of risks. That is, many risks were high impact, low frequency and occupied the same spot on the graphic output, described below as a "heat map," limiting its usefulness in identifying areas of focus.

RET2 was developed to address these deficiencies. RET2 employed a 7 × 7 matrix with additional specificity included in the criteria definitions. The algorithm was changed to a logarithmic scale to increase differentiation between risks and provide a better view of relative priority of risks. One year after implementing RET2, the EORM team revisited the definitions within the impact criteria and made adjustments to the descriptions in the "Reliability" impact category[2] to address LOB feedback. Although relative ranking did not change significantly between RET2 and RET2.1, the descriptions within Reliability better resonated with the LOBs using the tool.

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1 The P95 scenario is based on the concept of plotting a range of outcomes along a distribution and choosing the 95th percentile event for the purposes of the risk discussion. In practice, for many risks—in the absence of quantitative support—PG&E identifies a reasonably probable worst case scenario rather than a range of outcomes.

2 The six impact categories in the RET model are described in the next section.

Additionally, RET2.1 included increased flexibility in the frequency criteria. No longer are risk assessments limited to seven frequency categories. If there are data to support a specific frequency, e.g., through the use of probabilistic risk assessments, LOBs may use that data to calculate the risk score.

3. RET2.1

a. Inputs

1) Risk Score

As mentioned above, the RET2.1 is used to establish a number, called a risk score for each risk to establish relative priority for discussion purposes. The RET2.1 score is a calculation based on a SME discussion of the risk associated with the P95 scenario. The potential impacts of the scenario across six impact categories are then scored between 1 and 7 (7 being the greatest impact). The six impact categories are: Safety, Environmental, Compliance, Reliability, Trust and Financial. Once the impact is articulated, a frequency or probability based on data and subject matter expertise is assigned to each risk scenario. The algorithm discussed in Attachment A is then applied to create a score between 1 and 10,000.

2) Risk Status

When a risk is first identified, its status is denoted as “black” indicating that a risk assessment must be completed to determine a current residual risk score. During the risk assessment, the risk owner will gather as much data and expertise on the subject to fully characterize the risk drivers and controls and to score the risk.

Once the risk assessment is complete, the team determines what level of control status should be recommended to the LOB Risk and Compliance Committee. The following statuses are available:

- Red – controls not adequate
- Amber – controls need strengthening
- Green – controls are adequate

A risk response plan is created for a risk with Red or Amber status. The response plan includes a set of mitigations based on an alternatives analysis to determine the best course of action to reduce the risk and strengthen controls.

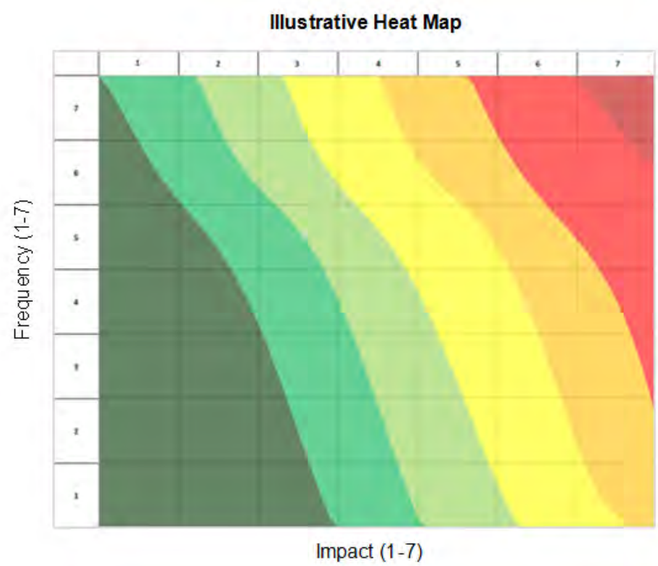
Over time, risk scores tend to be more static than the risk status. The risk status should change toward green as the mitigations are implemented and the controls are strengthened to an adequate level. The risk score will only change if mitigations fundamentally adjust the impact or frequency levels. In other words, impact scores may change only if mitigations can physically prevent or reduce the impact of the P95 scenario.

For example, if the P95 scenario risk is “a car accident which may result in a death,” a mitigant such as a physical divider between the lanes could change the worst case probable P95 scenario from fatality (head-on collision), to “a car accident which may result in a serious injury (i.e., hitting the divider).” This will drop the impact score and, likely the frequency as well. However, physical mitigants are not always possible or practical. More often, mitigations are more likely to impact the frequency side of the equation. For instance, if a substation were to fail catastrophically, the impact always would likely be catastrophic. But it may be possible to make catastrophic failure less likely to occur by addressing the drivers of the risk by maintaining, inspecting and replacing equipment, and installing physical and cyber security measures.

b. Output

The output of RET 2.1 is a risk score for each risk. These scores can be mapped on a “heat map” that graphically portrays the frequency and impact scores. An illustrative heat map is shown in Figure 2-1.

FIGURE 2-1
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE HEAT MAP



The y-axis on the heat map represents the frequency score, while the x-axis represents the impact score. The upper right hand corner of the heat map represents the highest risks; the lower left hand corner represents the lowest risks.

Because each LOB calculates its own risk scores, LOBs participate in calibration sessions to ensure consistency in scoring. SMEs and risk managers calibrate risks internal to their LOB and then the EORM team facilitates cross-LOB calibration sessions to ensure risks from different parts of the business are evaluated consistently. During each of these sessions, participants challenge assumptions and other inputs to risk scores to ensure there is alignment in how risks were evaluated. Once the calibration is complete, top risks to PG&E are selected for discussion in PG&E's Session D meeting.

4. Illustrative Example

An example helps to illustrate how RET 2.1is used to create a risk score from a risk assessment. Consider the risk of "Failure of Distribution Overhead Primary Conductor," defined as:

> The failure of or contact with energized electric distribution primary conductor may result in public or employee safety issues, significant environmental damage (fire), prolonged outages, or significant property damage. Energized wires down events are also considered part of this risk.

In this case, the P95 scenario is described as: A fatality due to unintentional third-party tree worker contact with an in place conductor, in conjunction with an investigation that finds compliance violations such as lack of signage, or insufficient clearance.

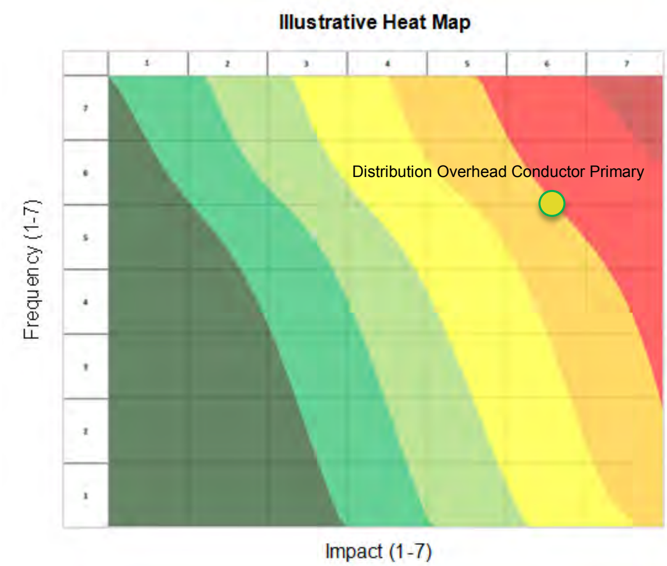
Once defined, the risk assessment team scores the risk by determining the impacts across the six impact categories (see Attachment B) and the frequency of such an event, and captures those determinations in the RET. In this case, the following scores were assigned:

- Safety impact: A 6 (Severe) impact captures the potential for a fatality to occur if contact was made with a distribution conductor. This is based on industry data and experience.
- Environmental impact: Under the scenario, there would be a 1 (Negligible) impact on the environment.
- Compliance impact: The scenario assumes a compliance violation, which was rated as a 3 (Moderate) impact by the team based on industry experience.
- Reliability impact: The team reviewed outage history that would occur relative to the incident and determined that a 3 (Moderate) impact described the potential impact.
- Trust impact: The team determined a 2 (Minor) impact believing that there may be a single report of the event in a media outlet near the location of the incident, were it to occur.
- Financial impact: Available data supports a 4 (Major) impact.

Finally the team reviewed the scenario, the impact scores, and the data around the drivers and controls and determined that a frequency level of 5, or once every one to three years, was appropriate.

The six impact scores and the frequency level are then input into the tool, producing a final risk score of 408. The results of the scoring of the Overhead Conductor Risk can be displayed on the heat maps as shown.

FIGURE 2-2
PACIFIC GAS AND ELECTRIC COMPANY
MAPPED RISK SCORE FOR OVERHEAD CONDUCTOR



D. Areas for Focus and Improvement

1. Where PG&E Is Compared to Our Peers

Informed by industry benchmarking studies, the recommendations of the Independent Review Panel, and a third-party consultant, PG&E has moved from having an “industry standard” enterprise risk management program to having an “industry-leading” EORM Program. PG&E’s EORM Program is leading as evidenced by the risk-informed process of integrated planning and the widespread support for risk management in terms of personnel and management attention. Senior management regularly engages in discussions about risk, the state of controls and mitigation plans, and has increased the focus on developing and monitoring key measures that provide insight into how risks are being managed.

Today, PG&E is in a position where each LOB knows and understands the risks associated with their business and the relative importance of those risks with respect to the potential impact they could have on the achievement of objectives. And the LOBs use this information to inform strategies and resource allocation.

PG&E is proud of where it is today in terms of risk management. That is not to say there is no room for improvement.

2. Key Challenges

Effective risk management is an iterative process. As new data becomes available, operating and environmental conditions change, and technology improves, so does PG&E's ability to identify, evaluate, prioritize and mitigate risks. As does PG&E's ability to dedicate the appropriate amount of resources to manage our most important risks and to demonstrate the risk reduction benefits of the investments PG&E is making.

As PG&E identifies and integrates new data sources, it will develop a deeper, more granular understanding of the risks it faces and will be able to make better decisions as a result. When new information becomes available, risk management priorities may shift over time and it is important that PG&E remains dynamic in its response to that new information. This means that changes will be made to PG&E's plans and it will deploy resources accordingly. PG&E will identify risk mitigations that do not have the intended effect and will have to change course. PG&E will also identify new risks. As new information becomes available, risks that PG&E thought were important, may take a back seat to other, more pressing risks. PG&E's focus on data-driven decision making combined with the ability to pivot to address mitigation needs in a timely manner, will help PG&E operate in a safer and more efficient manner to the benefit of PG&E's customers, employees and the public.

a. Risk Quantification

As PG&E's EORM process has matured and progress has started to be documented, there has been an increased focus on data and quantification of risk to answer two basic questions: (1) Are we making progress in managing risk; and (2) How do we know?

In 2014, the EORM team in the Risk and Audit Organization implemented a risk management database to provide better oversight of risk management activities. Risk managers in each of the LOBs began identifying data needs and fulfilling them by gathering information from PG&E and industry sources, and analyzing it to better understand risks. The outcome of that work has been the development of metrics to track and manage risks. The availability of relevant data remains a challenge, however.

Often, it is not possible to tie mitigations directly to the absence of a risk event. For example, PG&E has invested in a number of activities to educate the public about the dangers of contact with energized conductors—a top public safety risk included on the Electric Operations Risk Register. It is very difficult to prove that someone did not touch an energized conductor because they heard an advertisement on the radio, or paid attention to a mobile pop-up advertisement while they were shopping at Home Depot, or were already aware of the danger.

In some cases, data can be obtained to confirm that mitigations are effective, but often PG&E must rely on the fact that it went through a reasonable process to identify the right things to do and PG&E may not be able to determine the effectiveness of an individual mitigation.

PG&E's goal remains to achieve the vision of data-driven, risk-based decision making to support safe, reliable, and affordable electric and gas service that is integrated into our planning process and becomes the foundation for our rate cases. With the core foundational components of an industry leading EORM program now in place, PG&E is working on refining its approach and improving the maturity of the process, with a focus on data and its application within EORM.

b. Risk Tolerance

Risk cannot be completely driven out of PG&E's—or any—business. Today, risk tolerance is implicitly defined by the resources allocated to manage specific risks. For example, PG&E has a robust program to manage Wildfire Risk that consists of an award-winning vegetation management program, equipment retrofits in high-risk areas, and enhanced inspections. As a result, tree-related outages are in the neighborhood of 17 per 1,000 miles, < 0.02 percent of trees in contact, and there are a small number of wildfires caused by PG&E equipment each year. It may be possible to drive tree-related outages to less than 17 per 1,000 miles, or to have less than 0.02 percent of trees in contact, but that would require a level of investment greater than what PG&E is making today. With limited resources—PG&E cannot do everything and must decide at what point it is okay to not mitigate the risk further—tradeoff decisions must be made. For example, additional

investment in managing wildfire risk requires that customers either pay more, or accept higher risk in another area. PG&E is using the EORM process to help decide where to dedicate additional resources, and specifically where it has determined the risk has a current residual risk that is higher than desired. PG&E's Risk Informed Budget Allocation process, described in Chapter 3, also helps direct resources to projects and programs that have the largest risk reduction impact.

In the 2017 General Rate Case showing, PG&E will illustrate the projects and programs intended to address key risks in each operational LOB. By showing how these activities for which PG&E is requesting funding relate to risk reduction, intervenors and other stakeholders can see what risks are affected when reductions in specific programs or elimination of specific projects are recommended. As a result of this discussion, the Commission, intervenors, and PG&E will together define risk tolerance for PG&E.

3. Areas of Future Activities

PG&E's EORM focus for the foreseeable future can be broadly categorized as "Continuous Improvement." PG&E is focused on refining our current processes and improving the specific mechanics of risk management, i.e., how PG&E measures risk, the analysis PG&E does around alternatives for mitigation, and how PG&E calculates progress in risk management through the use of effectiveness metrics.

The EORM team also will continue to work with the LOBs to:

- Develop data plans for top risks, identifying what data PG&E needs, what data it has, and how to fill the gaps.
- Improve existing guidance and support for alternatives analysis and documenting decisions related to mitigation activities.
- Develop more effectiveness metrics that measure the impact of mitigation activities on risks or drivers of risk, and those that provide insight into how a risk is performing over time, i.e., is the risk increasing or decreasing?

With the basic elements of industry-leading risk management now in place, PG&E's focus is on collectively "upping our game" in the area of risk management. In support of this, the EORM team will continue to sponsor

expert training on specific risk management topics (annual training that is provided to all risk managers across PG&E); conduct benchmarking and share best practices from internal and external sources across LOBs; and continue to promote a risk-aware culture through the continued inclusion of risk in our Integrated Planning Process.

In the coming years, PG&E will consider analytical approaches for quantifying risk reduction (meaning a reduction to the RET risk score). To do so will require appropriate data, perhaps over an extended period of time. This data will need to address (or avoid) the causation challenges described above. Based on the outcome of this effort, PG&E hopes to identify and implement techniques for quantifying risk reduction and their applicability to specific risks.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT A

RISK EVALUATION TOOL (RET) ALGORITHM

CHAPTER 2
ATTACHMENT A
RISK EVALUATION TOOL (RET) ALGORITHM

The algorithm used to calculate the risk score for each P95 risk scenario is divided into two parts. The first part assesses how often a risk event occurs (frequency). The second part assesses the significance of the overall impact of each risk event. The overall impact is the log of the resulting product of the weighted impact scores in the six categories: Safety; Environmental; Compliance; Reliability; Trust; and Financial.

The risk score is expressed by the following equation in the figure below, where f(Event) represents the frequency component of the algorithm and I(Event) represents the impact component:

RISK SCORE ALGORITHM

$$\mathbf{RS}_{\mathbf{(Event)}} = k^{[0.5\ \mathrm{Log}\,(\boldsymbol{f}_{\boldsymbol{(Event)}}) + \boldsymbol{I}_{\boldsymbol{(Event)}}]}$$

Where	**f** is the number of occurrences expected over a one-year time horizon
And	***I*** is the weighted impact of the event
And	**k** is the scalar and is a fixed value of 3.16 (the square root of 10)
And	**0.5** s a standard factor used to calculate the variance of the aggregate impact of uncorrelated events.

The risk score calculation enables risk managers to calculate the “net risk impact” over a range of potential outcomes that occur at different frequencies. For example, gas leaks of various grades occur at various frequencies, and some of those leaks – if left unaddressed – could cause a range of impacts ranging from negligible to potentially catastrophic. The calculation enables risk managers to take that data and generate a risk score that contemplates the probable worst case, or a 95th percentile event.

“k” is a scalar used to calibrate the risk scores to cover a range of 1 to 10,000 to create adequate separation between risks for the purposes of facilitating a management discussion.

PG&E has mapped the six categories to our goals of safe, reliable and affordable service, and weighted them, as follows:

GOAL MAPPING TO RET IMPACT CATEGORIES

Company Goal	Company Goal Weight (%)	RET Impact Categories	RET Category Weight (%)
Safe	40%	Safety	30%
		Environmental	5
		Compliance	5
Reliable	30	Reliability	25
		Trust	5
Affordable	30	Financial	30
Total	100%		100%

The weighting shown above places more importance on certain objectives over others. To balance the importance of the weighting and the magnitude of the impact, the weightings are applied at the magnitude level (10^{I}) of the impact groups. Therefore, $I_{(Event)}$ can be expressed as shown in the figure below:

IMPACT WEIGHTING

$$I_{(Event)} = \text{Log}\left(\sum_{j=1}^{6} \mathbf{Wj} * 10^{\mathbf{Ij}}\right)$$

Where I_j ***(Safety, Environmental, Reliability, Financial, Reputation, Compliance)*** is the impact level of an impact group of an event

And W_j ***(Safety, Environmental, Reliability, Financial, Reputation, Compliance)*** is the weight applied to the impact group of an event

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT B

RISK ASSESSMENT CATEGORIES

CHAPTER 2
ATTACHMENT B
RISK ASSESSMENT CATEGORIES

FREQUENCY DESCRIPTIONS

Frequency Level	Frequency Description	Frequency per Year
Common (7)	> 10 times per year	F = > 10
Regular (6)	1-10 times per year	F = 1 – 10
Frequent (5)	Once every 1-3 years	F = 1 - 0.3
Occasional (4)	Once every 3-10 years	F = 0.3 - 0.1
Infrequent (3)	Once every 10-30 years	F = 0.1 - 0.033
Rare (2)	Once every 30-100 years	F = 0.033 - 0.01
Remote (1)	Once every 100 + years	F = <0.01

SAFETY IMPACT DESCRIPTIONS

Impact Level	Description
Catastrophic (7)	**Fatalitie**s: Many fatalities and life threatening injuries to the public or employees.
Severe (6)	**Fatalities:** Few fatalities and life threatening injuries to the public or employees.
Extensive (5)	**Permanent/Serious Injuries or Illnesses:** Many serious injuries or illnesses to the public or employees.
Major (4)	**Permanent/Serious Injuries or Illnesses:** Few serious injuries or illnesses to the public or employees.
Moderate (3)	**Minor Injuries or illnesses:** Minor injuries or illnesses to many public members or employees.
Minor (2)	**Minor Injuries or illnesses:** Minor injuries or illnesses to few public members or employees.
Negligible (1)	No injury or illness or up to an un-reported negligible injury.

ENVIORNMENTAL IMPACT DESCRIPTIONS

Impact Level	Description
Catastrophic (7)	**Duration:** Permanent or long-term damage greater than 100 years; or **Hazard Level/Toxicity:** Release of toxic material with immediate, acute and irreversible impacts to surrounding environment; or **Location:** Event causes destruction of a place of international cultural significance; or **Size:** Event results in extinction of a species.
Severe (6)	**Duration:** Long-term damage between 11 years and 100 years; or **Hazard Level/Toxicity:** Release of toxic material with acute and long-term impacts to surrounding environment; or **Location:** Event causes destruction of a place of national cultural significance; or **Size:** Event results in elimination of a significant population of a protected species.
Extensive (5)	**Duration:** Medium-term damage between 2 and 10 years; or **Hazard Level/Toxicity:** Release of toxic material with a significant threat to the environment and/or release with medium-term reversible impact; or **Location:** Event causes destruction of a place of regional cultural significance; or **Size:** Event results in harm to multiple individuals of a protected species.
Major (4)	**Duration:** Short-term damage of up to 2 years; or **Hazard Level/Toxicity:** Release of material with a significant threat to the environment and/or release with short-term reversible impact; or **Location:** Event causes destruction of an individual cultural site; or **Size:** Event results in harm to a single individual of a protected species.
Moderate (3)	**Duration:** Short-term damage of a few months; or **Hazard Level/Toxicity:** Release of material with a moderate threat to the environment and/or release with short-term reversible impact; or **Location:** Event causes damage to an individual cultural site; or **Size:** Event results in damage to the known habitat of a protected species.
Minor (2)	**Duration:** Immediately correctable; or contained within a small area.
Negligible (1)	Negligible to no damage to the environment.

COMPLIANCE IMPACT DESCRIPTIONS

Impact Level	Description
Catastrophic (7)	**Adverse Regulatory Actions:** Action resulting in closure, split, or sale of PG&E.
Severe (6)	**Adverse Regulatory Actions:** Cease and desist orders are delivered by regulators. Critical assets and facilities are forced by regulators to be shutdown.
Extensive (5)	**Adverse Regulatory Actions:** Governmental, regulator investigations, and enforcement actions, lasting longer than a year. Violations that result in multiple large non-financial sanctions; or **Increased Regulatory Oversight:** Regulators force the removal and replacement of management positions. Regulators begin Company monitoring activities.
Major (4)	**Adverse Regulatory Actions:** Violations that result in significant fines or penalties above and beyond what is codified or a regulator enforces non-financial sanctions; or **Expanded Regulations:** Significant new and updated regulations are enacted as a result of an event
Moderate (3)	**Adverse Regulatory Actions:** Violations that result in fines or penalties
Minor (2)	**Adverse Regulatory Actions:** Self-reported or regulator identified violations with no fines or penalties.
Negligible (1)	No compliance impact up to an administrative impact.

RELIABILITY IMPACT DESCRPTIONS

Impact Level	Description
Catastrophic (7)	**Location:** Impacts an entire metropolitan area, including critical customers, or is systemwide; and **Duration:** Disruption of service of more than a year due to a permanent loss to a nuclear facility, hydro facility, critical gas or electric asset; or **Customer Impact:** Unplanned outage (net of replacement) impacts more than 1 million customers; or EO: 14 million total customer hours, or more than 1 million mega-watt hours (MWh) total load GO: 10 million total customer hours, or reduction of capacity greater than or equal to 2.1 Bcf/d for seven months ES: 40 percent of utility-owned generating fleet unavailable for one year
Severe (6)	**Location:** Impacts multiple critical locations and critical customers; or **Duration:** Substantial disruption of service greater than 100 days; or **Customer Impact:** Unplanned outage (net of replacement) impacts more than 100k customers; or EO: 1.2 million total customer hours, or more than 100 thousand MWh total load GO: one million total customer hours, or reduction of capacity greater than 1.2 billion cubic feet per day (Bcf/d), but less than for seven months ES: 20 percent of utility-owned generating fleet unavailable for one year
Extensive (5)	**Location:** Impacts multiple critical locations or customers; or **Duration:** Disruption of service greater than 10 days; or **Customer Impact:** Unplanned outage (net of replacement) impacts more than 10k customers; or EO: 100 thousand total customer hours, or more than 10 thousand MWh total load; GO: 100 thousand total customer hours, or reduction of capacity greater than or equal to 0.6 Bcf/d for seven months ES: 10 percent of utility-owned generating fleet unavailable for one year
Major (4)	**Location:** Impacts a single critical location; or **Duration:** Disruption of service greater than one day; or **Customer Impact:** Unplanned outage (net of replacement) impacts more than one thousand customers; or EO: 8 thousand total customer hours, or more than one thousand MWh total load GO: 10 thousand total customer hours, or reduction of capacity greater than or equal to 0.3 Bcf/d for seven months ES: 2 percent of utility-owned generating fleet unavailable for one year

RELIABILITY IMPACT DESCRIPTIONS (CONTINUED)

Moderate (3)	**Location:** Impacts a small area with no disruption of service to critical locations; or **Duration:** Disruption of service of up to one full day; or **Customer Impact:** Unplanned outage (net of replacement) impacts more than 100 customers; or EO: 600 total customer hours, or more than 100 MWh total load GO: one thousand total customer hours, or reduction of capacity greater than or equal to 0.1 Bcf/d for seven months ES: one percent of utility-owned generating fleet unavailable for one year
Minor (2)	**Location:** Impacts a small localized area with no disruption of service to critical locations; or **Duration:** Disruption of up to three hours; or **Customer Impact:** Unplanned outage (net of replacement) impacts less than 100 customers; or EO: Less than 600 total customer hours, or less than 100 MWh total load; GO: Less than one thousand total customer hours, or reduction of capacity greater than or equal to 0.01 Bcf/d for seven months ES: 0.1 percent of utility-owned generating fleet unavailable for one year
Negligible (1)	No reliability to negligible impacts.

TRUST IMPACT DESCRIPTIONS

Impact Level	Description
Catastrophic (7)	**Duration:** Ongoing impacts for more than 10 years; and **Media:** Event is heavily reported from local through international media outlets and social media channels, with influential third parties dominating media coverage; various inaccurate information is widely reported; or **Political:** Devastating nationwide broad-based political pressure demanding intense long term outreach to policymakers and key stakeholders; or **Customer Satisfaction:** Greater than 50 percent loss of customer satisfaction through survey results; or **Company Brand:** Relationships are severed and trust is completely lost
Severe (6)	**Duration:** Ongoing impacts between 1 and 10 years; and **Media:** Event is heavily reported from local through national media outlets and social media channels, with influential third parties dominating media coverage, and various inaccurate information is widely reported; or **Political:** Extreme statewide broad-based political pressure demanding concentrated outreach to policymakers and key stakeholders; or **Customer Satisfaction:** 21-50 percent loss of customer satisfaction through survey results; or **Company Brand:** Event creates outrage and trust can't be fully recovered
Extensive (5)	**Duration:** Ongoing impacts between one quarter and one year; or **Media:** Event is widely reported in national media outlets and social media channels, with influential third parties dominating media coverage, and inaccurate information is reported; or **Political:** Severe territory wide political pressure demanding extensive outreach to policymakers and key stakeholders; or **Customer Satisfaction:** 4-20 percent loss of customer satisfaction through survey results; or **Company Brand:** Event creates serious concerns of company management while trust is severely diminished
Major (4)	**Duration:** Ongoing impacts between one week and one quarter; or **Media:** Event is heavily reported in local through national media outlets and social media channels, with influential third parties dominating media coverage, and inaccurate information is reported; or **Political:** Major territory wide political pressure demanding major outreach to policymakers and key stakeholders; or **Customer Satisfaction:** one to three percent loss of customer satisfaction through survey results; or **Company Brand:** Management is questioned and trust is diminished

TRUST IMPACT DESCRIPTIONS
(CONTINUED)

Moderate (3)	**Duration:** Short term coverage for up to one week. **Media:** Event is reported in multiple local media outlets and/or social media channels, with limited exposure beyond the coverage area; or **Political:** Moderate county level political pressure demanding moderate outreach to policymakers and key stakeholders; or **Customer Satisfaction:** Less than one percent loss of customer satisfaction through survey results; or **Company Brand:** Event isn't anticipated and trust is impacted; or
Minor (2)	**Duration:** Single report of the event. **Media:** Event is reported in a single local media outlet in the location where the event took place; or **Political:** Minimal political pressure demanding minimal outreach to policymakers and key stakeholders; or
Negligible (1)	No known reputation impact reported to a non-featured report.

FINANCIAL IMPACT DESCRIPTIONS

Impact Level	Description
Catastrophic (7)	**Financial Costs:** Damage to third-party properties, loss of assets and facilities, fines, lawsuits, restitution, remediation, restoration, cost of replacement energy, redistributed customer costs, amounting to a total impact > $5 billion in costs; or **Capital/Liquidity:** Ability to raise capital significantly impacted. Dramatic decrease in stock price of more than 50 percent for more than one year; or **Bankruptcy:** Risk of bankruptcy is imminent.
Severe (6)	**Financial Costs:** Damage to third-party properties, loss of assets and facilities, fines, lawsuits, restitution, remediation, restoration, cost of replacement energy, redistributed customer costs, amounting to a total impact between $500 million and $5 billion in costs; or **Capital/Liquidity:** Ability to raise capital is challenged. Dramatic decrease in stock price of more than 25 percent for more than one year.
Extensive (5)	**Financial Costs:** Damage to third-party properties, loss of assets and facilities, fines, lawsuits, restitution, remediation, restoration, cost of replacement energy, redistributed customer costs, amounting to a total impact between $50 million and $500 million in costs; or **Capital/Liquidity:** Ability to raise capital is hindered. Dramatic decrease in stock price of more than 10 percent for up to one year.
Major (4)	**Financial Costs:** Damage to third-party properties, loss of assets and facilities, fines, lawsuits, restitution, remediation, restoration, cost of replacement energy, redistributed customer costs, amounting to a total impact between $5 million and $50 million in costs.
Moderate (3)	**Financial Costs:** Damage to third-party properties, loss of assets and facilities, fines, lawsuits, restitution, remediation, restoration, cost of replacement energy, redistributed customer costs, amounting to a total impact between $500 thousand and $5 million in costs.
Minor (2)	**Financial Costs:** Damage to third-party properties, loss of assets and facilities, fines, lawsuits, restitution, remediation, restoration, cost of replacement energy, redistributed customer costs, amounting to a total impact between $50 thousand and $500 thousand in costs.
Negligible (1)	**Financial Costs:** Damage to third-party properties, loss of assets and facilities, fines, lawsuits, restitution, remediation, restoration, cost of replacement energy, redistributed customer costs, amounting to a total impact of less than $50 thousand in costs.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

COMPANYWIDE MODELS AND APPROACHES TO RISK INFORMED BUDGET ALLOCATION

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COMPANYWIDE MODELS AND APPROACHES TO RISK INFORMED BUDGET ALLOCATION

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CHAPTER 3
COMPANYWIDE MODELS AND APPROACHES TO RISK INFORMED BUDGET ALLOCATION

A. Overview

Pacific Gas and Electric Company (PG&E) uses a Risk Informed Budget Allocation (RIBA) process to inform the prioritization of budget for risk mitigation measures and other work in its portfolio. More specifically, the RIBA process provides scores for projects and programs by evaluating the worst reasonable direct impact (WRDI) of not performing the work. The RIBA process is used for capital and expense projects and programs in Electric Transmission, Electric Distribution, Power Generation, Gas Operations, and Diablo Canyon Power Plant, and is not currently used in other parts of the company. RIBA is an integral part of the Integrated Planning Process, and is also used throughout the year when budget tradeoff decisions are required due to changing circumstances.

B. PG&E's Risk Informed Budget Allocation Process

1. Purpose

RIBA's purpose is to provide a framework for making risk-informed budget decisions by risk scoring and categorizing proposed projects and programs in the operational lines of business (LOBs) capital and expense portfolios. These scores and categories provide data that are used in PG&E's Integrated Planning Process described in Chapter 1. The outputs of the process, the RIBA graphs,[1] are used during prioritization discussions within and across the LOBs.

2. Approach and Methodologies

a. Personnel

PG&E's Finance Department is responsible for: (i) maintaining the RIBA scoring model; (ii) leading the RIBA working group (discussed

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1 PG&E has included an illustrative RIBA graph in Section B.3.b. of this chapter.

below); (iii) promoting consistent use of the RIBA process across the LOBs; and (iv) incorporating the RIBA output into PG&E's Integrated Planning Process. The personnel within PG&E's Finance Department responsible for the RIBA process report to the Director of Economic and Project Analysis, who reports to the Vice President of Finance.

b. Committees

The RIBA team leads a RIBA working group that is comprised of representatives from Finance, Risk Management, Electric Operations, Gas Operations, and Nuclear Power Generation. The working group has a variety of responsibilities. It defines the scoring methodology and the risk and categorization flag taxonomies.[2] It resolves issues relating to consistency across the participating LOBs. The RIBA team also works closely with PG&E's Enterprise and Operational Risk Management (EORM) Program discussed in Chapter 2.

c. Processes and Timing

The RIBA cycle begins around April of each year after the conclusion of Session D in PG&E's Integrated Planning Process. At that point, investment planning teams within the LOBs develop a list of proposed projects and programs to meet the Company's strategies and goals. These projects and programs will include the risk control measures and mitigations identified in Session D. New projects and programs are risk scored by asset owners, engineers, project and program managers, and other subject matter experts (SME), and existing scores are reviewed to ensure they reflect current conditions. After the projects are scored, the RIBA team holds calibration sessions to promote consistent use of the risk criteria and categorization flags across the participating LOBs. These calibration sessions are attended by representatives from Finance, Risk Management, and the participating LOBs.

The calibration sessions are typically held in June prior to submittal of the LOB Session 1 material. RIBA stacked graphs and detailed risk

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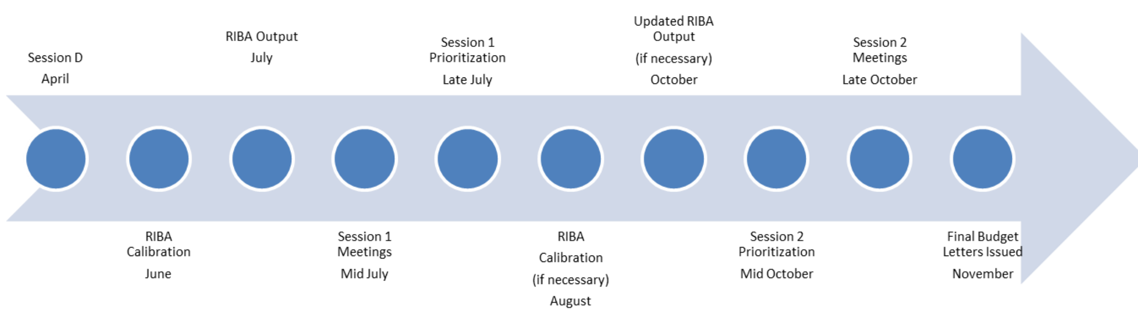
2 Categorization flags are described in Section 3.a. below and Attachment B.

information about projects and programs are submitted to Finance in late July, to support Session 1 prioritization discussions. It is during these prioritization discussions when resource and other constraints may drive adjustments to the proposed work portfolios of the LOBs. Additional calibration sessions—if required—would be held in August, and updated RIBA output would be submitted to Finance prior to Session 2 prioritization discussions, which are held in early October. Final budget letters[3] are usually sent to the LOBs in late November for the upcoming year. RIBA scores and categorizations are used throughout the year when budget trade-off decisions are required by changing circumstances.

FIGURE 3-1
PACIFIC GAS AND ELECTRIC COMPANY
PLANNING TIMELINE



3. The Model

RIBA scores are calculated in an Excel model. The template for the model is maintained by PG&E's Finance Department. Capital and expense projects and programs are risk scored based on the impact of the work on safety, reliability, and the environment. Work is also categorized based on compliance requirements, commitments and other considerations such as whether a project is in flight or is related to another project. For example,

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3 Budget letters are formal notifications to each of the LOBs, typically distributed in November, that set expense and capital targets for the following year.

related projects may be flagged together if it is prudent to complete such projects during the same plant outage or electric transmission clearance.

a. Inputs

The first step in risk scoring is to determine the WRDI of not performing the work. As in the RET2.1 model, the risk scores are based on the impact and likelihood of occurrence. The safety, environmental, and reliability impact and frequency scores are assigned based on the scoring taxonomy shown in Attachment A, and are summarized below, with 1 being negligible impact and 7 being catastrophic:

	Range Summary
Safety	7. Many fatalities and life threatening injuries to the public or employees. 1. No injury or illness or up to an un-reported negligible injury.
Environmental	7. Permanent or long-term damage greater than 100 years. 1. Negligible to no damage to the environment.
Reliability	7. Impacts an entire metropolitan area, including critical customers, or is systemwide. 1. Negligible to no reliability impacts.
Frequency	7. Imminent or already failed. 1. Once every 100+ years.

The process is as follows:

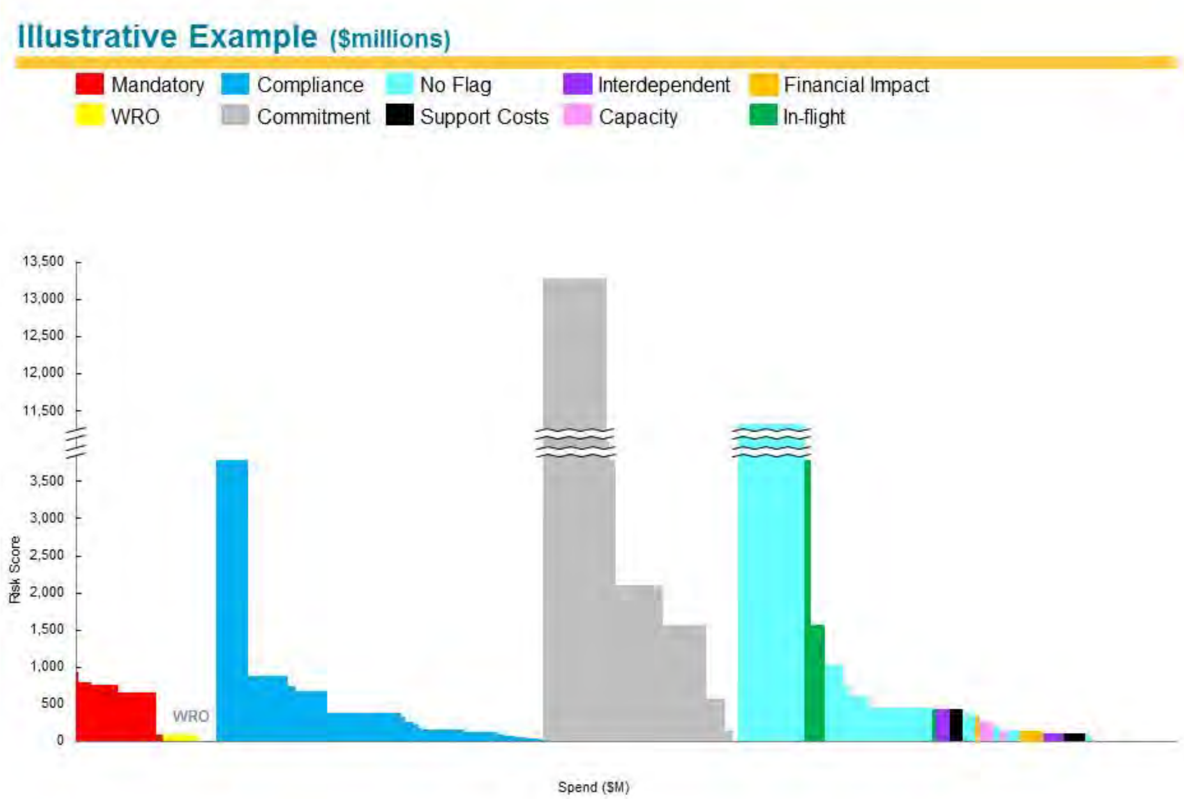
1. Use the prescribed 1-7 scoring scale to determine the WRDI on safety, reliability, and the environment of not doing the work; the model provides fields to enter each score and fields to enter notes to support the chosen score.
2. Use the prescribed 1-7 scoring scale to estimate the timing or frequency of these WRDI; enter the score and notes in the model.
3. Review and flag each proposed work item to reflect other non-risk drivers of the work. Required work categories are Mandatory, Compliance, Work Requested by Others (WRO), or Commitment. Additionally, all work may be flagged as In-Flight, Financial Benefits, Capacity, Inter-Relationship with other projects, and/or Support. These flags provide additional information that informs budget

decisions, as they identify key business reasons for performing the work.[4]

b. Outputs

Using the algorithm discussed in Attachment C, the output of the RIBA process is a risk scored portfolio that can be sorted in multiple ways (by flag, risk score, safety score, etc.) The results are also presented to management graphically. A simulated graph for illustrative purposes is shown below.

FIGURE 3-3
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE RIBA GRAPH



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4 See Attachment B, Flag Taxonomy, for a complete definition of the work categorization flags.

Dollars are shown on the x-axis and the RIBA score is shown on the y-axis, thus the width of the bar represents the proposed budget, and its height represents the RIBA score. The color of each bar represents the categorization of the work. The Mandatory, WRO, Compliance, and Commitment flags are mutually exclusive and designed to capture all required work. Any work assigned one of those flags would be graphed as such. The other flags are not mutually exclusive, and multiple flags may be assigned to non-required work. The LOBs can choose which flags to identify for purposes of generating a RIBA graph. Similar graphs can be generated that are sorted by risk score, program, or other means.

4. Illustrative Examples

The following projects illustrate the RIBA data and scoring of two projects associated with overhead conductor risk mitigation. The text is paraphrased from a RIBA scoring template submitted to Finance by Electric Operations. The scoring was done by SMEs in Electric Operations.

The purpose of the first project is to reconductor 1,440 circuit feet of copper conductor due to the number of splices on the line.[5]

Safety: This project received a Safety Impact Score of 6 and a Safety Frequency Score of 1. This was based on the possibility of a fatality as a result of the public contacting down overhead primary conductor. The conductor is located across the street from a public school. Historical data indicates 0.79 fatalities per year associated with the public contacting a down overhead primary conductor. PG&E estimates that 2,700 wire-down events will occur annually. The frequency of a fatal event is therefore 0.0003 (0.79/2,700) which translates to a frequency score of 1. These assumptions provide an overall Safety Risk Score of 178.

Environment: This project received an Environmental Impact Score of 1 and an Environmental Frequency Score of 1. This was based on the location of the line in an urban neighborhood, across the street from a public

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[5] Internally, the project is called "MADERA 1104 – RECONDUCTOR SUNSET AVE."

school. These assumptions provide an overall Environmental Risk Score of 1.

Reliability: This project received a Reliability Impact Score of 4 and a Reliability Frequency Score of 6. This was because these broken wires would lead to 3,161 Customers Experiencing a Sustained Outage (CESO) (CESO = 3,161, duration 6 + hours), impacts a middle school, and there have been four wires down outages on this line in the last three years. These assumptions provide an overall Reliability Risk Score of 178.

Total Risk Score: Summing the Safety, Environmental and Reliability Risk Scores gives a Total Risk Score for this Project of 357.

In terms of "flags," this project is not a required project, so in a RIBA graph it would appear within the discretionary work as No Flag showing an overall risk score of 357.

The purpose of the second project is to reconductor 200 circuit feet of Aluminum Conductor Steel Reinforced overhead conductor with Aluminum conductor and install two overhead cutouts.[6] This work will provide higher reliability and operational flexibility on the Tidewater 2107 circuit and will reduce the likelihood of a wire-down event.

Safety: This project received a Safety Impact Score of 6 and a Safety Frequency Score of 1, using the same scoring assumptions described for the first project. These assumptions provide an overall Safety Risk Score of 178.

Environment: This project received an Environmental Impact Score of 1 and an Environmental Frequency Score of 1. This was based on the location of the line in an urban neighborhood. These assumptions provide an overall Environmental Risk Score of 1.

Reliability: This project received a Reliability Impact Score of 3 and a Reliability Frequency Score of 5. This was because these broken wires would lead to 43 customers experiencing a sustained outage (CESO) (CESO = 43, duration 10 hours) and there have been two wires down

6 Internally, the project is called "RECON 1 SPAN LINE SIDE FU 1829 TW 2107."

outages on this line in the last three years. These assumptions provide an overall Reliability Risk Score of 23.

Total Risk Score: Combining the Safety, Environmental and Reliability Risk Scores gives a Total Risk Score for this Project of 202.

In terms of "flags," this project is not a required project, so in a RIBA graph it would appear within the discretionary work as No Flag showing an overall risk score of 202.

C. Areas of Focus and Improvement

Over the next three years, PG&E expects to work on the following areas of possible improvement for the RIBA process.

First, the RIBA team, the EORM team, and the LOBs will evaluate current differences in the weighting algorithms between RIBA and RET. PG&E intends to work toward alignment wherever possible, and validate differences where appropriate. The RIBA team will work closely with the EORM team to assure that improvements made in the EORM program are incorporated into RIBA. These types of improvements would include topics such as risk quantification and risk tolerance.

Second, the RIBA team is working with PG&E's Information Technology Department to incorporate RIBA into SAP Project Portfolio Management (PPM), which PG&E is currently implementing across the enterprise. PPM is an end-to-end solution that will enable PG&E to plan and manage its portfolio of work more effectively, efficiently and in a consistent manner across the entire company. PPM will allow standardized planning and management of work at the portfolio and program levels and will integrate the RIBA scoring model with other work attributes such as cost, schedule, approval status, resource availability, and accounting information. PPM will be integrated with SAP to facilitate rate case, Session 1 and Session 2 planning and reporting.

Third, PG&E is exploring the practicality of extending the RIBA process to other LOBs within PG&E. RIBA's initial focus was asset based, and focused on the core operational LOBs. The RIBA team is working with the investment planning and risk teams in the other LOBs to develop a risk-informed prioritization process that will improve the decision-making process in those organizations.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ATTACHMENT A

SCORING TAXONOMY

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SCORING TAXONOMY

The entire scoring taxonomy is presented here for completeness. The Safety and Environmental taxonomies are exactly the same as those used in RET2.1. There are some minor differences between RET2.1 and RIBA in the Reliability and Frequency taxonomies.

Impact Level	Safety
Catastrophic (7)	o **Fatalities:** Many fatalities and life threatening injuries to the public or employees.
Severe (6)	o **Fatalities:** Few fatalities and life threatening injuries to the public or employees.
Extensive (5)	o **Permanent/Serious Injuries or Illnesses:** Many serious injuries or illnesses to the public or employees.
Major (4)	o **Permanent/Serious Injuries or Illnesses:** Few serious injuries or illnesses to the public or employees.
Moderate (3)	o **Minor Injuries or illnesses:** Minor injuries or illnesses to many public members or employees.
Minor (2)	o **Minor Injuries or illnesses:** Minor injuries or illnesses to few public members or employees.
Negligible (1)	o No injury or illness or up to an un-reported negligible injury.

Impact Level	Environmental
Catastrophic (7)	**Duration:** Permanent or long-term damage greater than 100 years; or **Hazard Level/Toxicity:** Release of toxic material with immediate, acute and irreversible impacts to surrounding environment; or **Location:** Event causes destruction of a place of international cultural significance; or **Size:** Event results in extinction of a species.
Severe (6)	**Duration:** Long-term damage between 11 years and 100 years; or **Hazard Level/Toxicity:** Release of toxic material with acute and long-term impacts to surrounding environment; or **Location:** Event causes destruction of a place of national cultural significance; or **Size:** Event results in elimination of a significant population of a protected species.
Extensive (5)	**Duration:** Medium-term damage between 2 and 10 years; or **Hazard Level/Toxicity:** Release of toxic material with a significant threat to the environment and/or release with medium-term reversible impact; or **Location:** Event causes destruction of a place of regional cultural significance; or **Size:** Event results in harm to multiple individuals of a protected species.
Major (4)	**Duration:** Short-term damage of up to 2 years; or **Hazard Level/Toxicity:** Release of material with a significant threat to the environment and/or release with short-term reversible impact; or **Location:** Event causes destruction of an individual cultural site; or **Size:** Event results in harm to a single individual of a protected species.
Moderate (3)	**Duration:** Short-term damage of a few months; or **Hazard Level/Toxicity:** Release of material with a moderate threat to the environment and/or release with short-term reversible impact; or **Location:** Event causes damage to an individual cultural site; or **Size:** Event results in damage to the known habitat of a protected species.
Minor (2)	**Duration:** Immediately correctable; or contained within a small area.
Negligible (1)	Negligible to no damage to the environment.

Impact Level	Reliability
Catastrophic (7)	**Location:** Impacts an entire metropolitan area, including critical customers, or is system-wide; and **Duration:** Disruption of service of more than a year due to a permanent loss to a nuclear facility, hydro facility, critical gas or electric asset; or **Customer Impact:** Unplanned outage (net of replacement) impacts more than 1 million customers; or EO: 50 million total customer hours, or more than 1 million mwh total load; GO: 10 million total customer hours, or reduction of capacity greater than or equal to 2.1 Bcf/d for 7 months DCPP: 4,000% miss of equivalent forced outage factor and/or availability target PG: 40% or more of utility-owned generating fleet unavailable for 1 year
Severe (6)	**Location**: Impacts multiple critical locations and critical customers; or **Duration**: Substantial disruption of service greater than 100 days; or **Customer Impact**: Unplanned outage (net of replacement) impacts more than 100k customers; or EO: 5 million total customer hours, or more than 100k mwh total load; GO: 1 million total customer hours, or reduction of capacity greater than or equal to 1.2 Bcf/d for 7 months; DCPP: 2,000% miss of equivalent forced outage factor and/or availability target PG: 10% or more of utility-owned generating fleet unavailable for 1 year
Extensive (5)	**Location:** Impacts multiple critical locations or customers; or **Duration:** Disruption of service greater than 10 days; or **Customer Impact:** Unplanned outage (net of replacement) impacts more than 10k customers; or EO: 500k total customer hours, or more than 10k mwh total load; GO: 100k total customer hours, or reduction of capacity greater than or equal to 0.6 Bcf/d for 7 months; DCPP: 500% miss of equivalent forced outage factor and/or availability target PG: 2.75% or more of utility-owned generating fleet unavailable for 1 year

Major (4)	**Location:** Impacts a single critical location; or **Duration:** Disruption of service greater than 1 day; or **Customer Impact:** Unplanned outage (net of replacement) impacts more than 1k customers; or EO: 50k total customer hours, or more than 1k mwh total load; GO: 10k total customer hours, or reduction of capacity greater than or equal to 0.3 Bcf/d for 7 months; DCPP: 100% miss of equivalent forced outage factor and/or availability target PG: 0.75% or more of utility-owned generating fleet unavailable for 1 year
Moderate (3)	**Location:** Impacts a small area with no disruption of service to critical locations; or **Duration:** Disruption of service of up to 1 full day; or **Customer Impact:** Unplanned outage (net of replacement) impacts more than 100 customers; or EO: 5k total customer hours, or more than 100 mwh total load; GO: 1k total customer hours, or reduction of capacity greater than or equal to 0.1 Bcf/d for 7 months; DCPP: 50% miss of ES equivalent forced outage factor and/or availability target PG: 0.20% or more of utility-owned generating fleet unavailable for 1 year
Minor (2)	**Location:** Impacts a small localized area with no disruption of service to critical locations; or **Duration:** Disruption of up to 3 hours; or **Customer Impact:** Unplanned outage (net of replacement) impacts less than 100 customers; or EO: Less than 5k total customer hours, or less than 100 mwh total load; GO: Less than 1k total customer hours, or reduction of capacity greater than or equal to 0.01 Bcf/d for 7 months; DCPP: 5% miss of ES equivalent forced outage factor and/or availability target PG: 0.05% or more of utility-owned generating fleet unavailable for 1 year
Negligible (1)	o No reliability to negligible impacts.

Frequency Taxonomy

Level	Description	Frequency Description	Frequency per year
7	Imminent or Already failed	> 10 times per year	F = 10 - 100
6	Within 1 year	1 - 10 times per year	F = 1 - 10
5	Within 3 years	Once every 1-3 years	F = 0.3 -1.0
4.5	Within 5 years	Once every 3 - 5 years	F= 0.2 -0.3
4	Within 10 years	Once every 5-10 years	F = 0.1 -0.2
3	Within 30 years	Once every 10 - 30 years	F = 0.033 - 0.1
2	Within 100 years	Once every 30 - 100 years	F = 0.01 - 0.033
1	100+ years	Once every 100 + years	F = 0.001 - 0.01

RIBA Scoring Matrix

	Impact Levels						
	Negligible	Minor	Moderate	Major	Extensive	Severe	Catastrophic
Frequency Level	1	2	3	4	5	6	7
Common (7)	10	32	100	316	1,000	3,162	10,000
Regular (6)	6	18	56	178	562	1,778	5,623
Frequent (5)	2	7	23	74	234	740	2,340
Often (4.5)	2	7	21	67	211	668	2,113
Occasional (4)	2	6	18	56	178	562	1,778
Infrequent (3)	1	4	14	43	135	427	1,351
Rare (2)	1	3	10	32	100	316	1,000
Remote (1)	1	2	6	18	56	178	562

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CHAPTER 3

ATTACHMENT B

FLAG TAXONOMY

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FLAG TAXONOMY

Commitments and requirements (Choose one of the following, or None)

Mandatory	• Must be conducted in the budget or forecast year to comply with a regulation
Regulatory Compliance	• Work that is required to comply with a regulation, but that does not meet the definition of 'Mandatory'
Commitment	• The company has made a specific commitment to completing the proposed work in a public forum or to regulators. Includes Rule 20A work
WRO	• Work requested by others spans agricultural-related requests, and new business (customer connections)

Other Considerations (Select YES OR NO for each of the following)

In-flight	• Under construction or 50% of total expected cost committed as of the beginning of the budget year (e.g., if in 2014 planning for 2015, then as of 1/1/2015). Applies to project work that has a defined scope. For a complete definition of a project refer to the Project approval Procedure, Utility Procedure: PM-1001P-01.
Inter-relationships with other projects	• Used to indicate that the proposed work either must, or should, be done in conjunction with other work (e.g., opportunity created by a planned outage or having a trench open).
Capacity	• Work meant to meet changes in system demand or load growth in the future
Support	• IT Apps & Infrastructure; Tools & Equipment; Fleet; Buildings, Roads and Physical Infrastructure; Training

Financial Impact (Select Hard, Soft, or None)

Hard financial benefits	• Any sustainable net cost reduction (measured in dollars) from an established point of reference.
Soft financial benefits	• Any productivity or business improvement from an established business standard.
None	• If there are no financial benefits.

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CHAPTER 3

ATTACHMENT C

RISK-INFORMED BUDGET ALLOCATION TOOL ALGORITHM

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RISK-INFORMED BUDGET ALLOCATION TOOL ALGORITHM

The equation for each risk score is the same equation in RET2.1 and is:

$$RS = k^{(0.5\,Log\,(f) + I)}$$

Log (f) is determined from the following table

Frequency Level	*1*	*2*	*3*	*4*	*4.5*	*5*	*6*	*7*
Log (f)	-3.0	-2.0	-1.5	-1.0	-0.7	-0.5	1.0	2.0

Just as in RET2.1 the RIBA algorithm also allows for a direct input of the frequency by the scorer. The RIBA algorithm also allows a Frequency Level of 4.5. This option was added because SMEs performing the RIBA scoring felt that in many cases they had sufficient knowledge and data to make the distinction between a failure every three to five years and a failure every three to ten years. The resulting scores are shown below.

RIBA SCORING MATRIX

	Impact Levels						
	Negligible	Minor	Moderate	Major	Extensive	Severe	Catastrophic
Frequency Level	1	2	3	4	5	6	7
Common (7)	10	32	100	316	1,000	3,162	10,000
Regular (6)	6	18	56	178	562	1,778	5,623
Frequent (5)	2	7	23	74	234	740	2,340
Often (4.5)	2	7	21	67	211	668	2,113
Occasional (4)	2	6	18	56	178	562	1,778
Infrequent (3)	1	4	14	43	135	427	1,351
Rare (2)	1	3	10	32	100	316	1,000
Remote (1)	1	2	6	18	56	178	562

The total risk score is the sum of the Safety, Environmental, and Reliability scores (therefore all three are weighted equally). The component scores are available to reviewers in order to provide a more detailed view into the work portfolio.

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CHAPTER 4

ELECTRIC OPERATIONS AND NUCLEAR POWER GENERATION

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ELECTRIC OPERATIONS AND NUCLEAR POWER GENERATION

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CHAPTER 4
ELECTRIC OPERATIONS AND NUCLEAR POWER GENERATION

A. Introduction

This chapter describes how Pacific Gas and Electric Company's (PG&E) Electric Operations (EO) organization is using the Enterprise and Operational Risk Management (EORM) Program to manage electric system risks. This portion is sponsored by Eric Back, Director, Compliance and Risk Management for Electric Operations. EO is responsible for the electric transmission and distribution (T&D) systems, fossil, hydro, and other non-nuclear generating facilities and energy procurement.

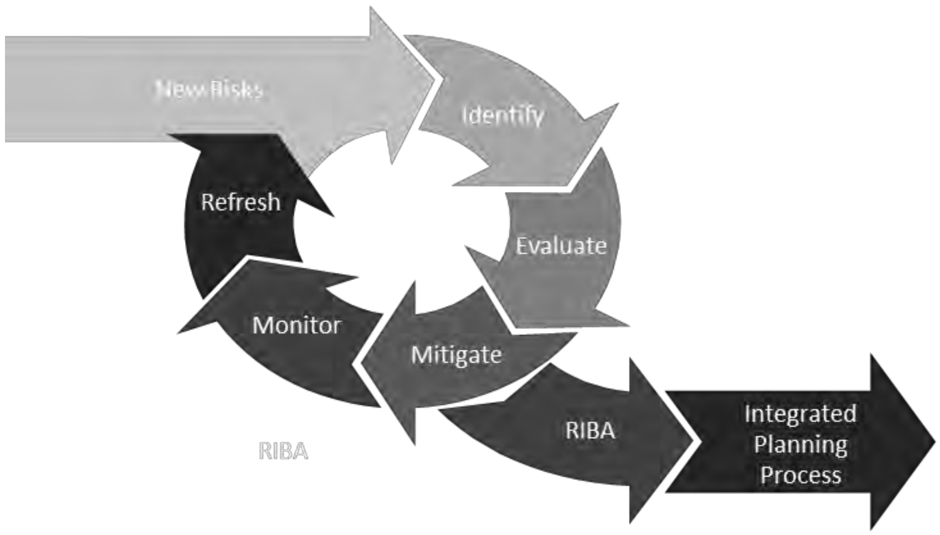
This chapter also describes how PG&E's Nuclear Power Generation organization is managing risks associated with PG&E's nuclear facilities. The nuclear portion is sponsored by Cary D. Harbor, Director, Compliance Alliance and Risk for Nuclear Power Generation.

B. General Processes

1. Electric Operations

EO is implementing the EORM Program described in Chapter 2, "Companywide Models and Approaches for Assessing Risk," to manage electric system risks. This program requires EO to identify, evaluate, mitigate, and monitor risks. The process provides a repeatable and consistent method of managing risks and is an important element of PG&E's Integrated Planning Process. Figure 4-1, is a high-level illustration of the risk management framework.

FIGURE 4-1
PACIFIC GAS AND ELECTRIC COMPANY
RISK MANAGEMENT FRAMEWORK



The remainder of this EO section is organized as follows:

- Organizational Structure – Describes EO risk management personnel and committees.
- Risk Register – Describes the codification of identified risks.
- Risk Evaluation – Describes the tools EO uses to score items on the Risk Register.
- Risk Management Software Applications – Describes software applications that PG&E is developing to assist with risk management activities.
- Risk Informed Budget Allocation (RIBA) – As generally described in Chapter 3, the process EO uses to "risk score" projects and programs to inform budgeting decisions.

In addition to the models described in Chapters 2 (Risk Evaluation Tool) and 3 (RIBA), EO also uses a variety of tools (e.g., spreadsheets and databases) that provide information regarding asset condition and in some instances potential replacement priority. In some cases the information from these tools is used to inform the models described in Chapters 2 and 3 and is also used in analysis by subject matter experts (SME) during the risk assessment process.

a. Organizational Structure

Chapter 2 describes how each line of business (LOB) has resources dedicated to coordinating risk management activities within the LOB; and collaborating on risk management activities across the LOBs. The risk management organization within EO is the System Safety and Risk team and consists of a senior manager and several full-time risk analysts. This team reports to the Director for Compliance and Risk Management, who reports to the Vice President for Electric Operations Asset Management.

The System Safety and Risk team is responsible for implementing the EORM Program for the following areas:

- Electric Transmission Lines
- Electric Transmission and Distribution Substations
- Electric Distribution Lines
- Non-Nuclear Power Generation Facilities
- Energy Procurement

Items in the Risk Register (described in the next section) are assigned to a risk owner (typically a director) who is responsible for ensuring the accuracy of a risk's evaluation and implementing risk response plans and mitigations. SMEs working within EO assist the risk owners and the EO System Safety and Risk team when evaluating risks and creating risk response plans.

Also, EO has a Risk and Compliance Committee (RCC). The RCC is chaired by EO's Executive Vice President and is comprised of her executive leadership team. This committee meets monthly to review current risk-related topics and approve various items such as risk assessments, risk mitigation measures, and changes to the Risk Register.

b. Risk Register

PG&E uses risk registers to log and classify risks. The EO Risk Register currently includes 72 risks.[1] The risks are categorized as

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[1] For a full list of all risks sorted by score and category, see Attachment A of this chapter.

enterprise risks, asset risks, process risks, or energy policy risks. These different types of risk are defined below.

Enterprise Risks (5): Enterprise risks are risks that could have a catastrophic impact on PG&E if they were to occur.

Asset Risks (43): Risks that have consequences associated with component failure or malfunction. These are further divided into:

- Transmission Overhead Risks
- Distribution Overhead Risks
- Transmission and Distribution Underground Risks
- Substation Risks
- Power Generation Risks

Process Risks (14): Process-based risks have consequences associated with business processes, programs, PG&E personnel, etc.

Energy Policy Risks (10): These risks are generally financial risks related to bulk power operations, energy markets, portfolio management, etc.

Examples of key public safety risks from the EO Risk Register include wildfire, hydro system safety, and asset-related risks associated with the electric T&D system. Energy policy and the majority of process risks are not considered key public safety risks.

c. Risk Evaluation

EO uses two tools to evaluate items on the Risk Register:

- The Risk Evaluation Tool (RET)
- Risk Assessments

1) Application of RET to Electric Operations

EO uses RET, described in Chapter 2, Section C, to establish a risk score for each risk in the Risk Register. For the majority of uses, EO uses the RET as directed by the EORM Program and no modifications are made to the algorithm, frequency scales, or impact group weightings. While EO does not modify the RET model itself, a variety of data and judgment are inherent when applying the frequency and impact scales of the model and in the formulation of

the P95 scoring scenarios.[2] How the RET is used in EO's risk assessment process is described more fully in the next section.

It is important to note that there are distinctions between (i) Risk Register scores, (ii) program/project risk scores (which are discussed later in the Risk Informed Budget Allocation section of this chapter), and (iii) an individual asset risk score which is discussed in the System Tool for Asset Risk (STAR) and Generation Risk Information Tool (GRIT) sections, later in this chapter.

2) Risk Assessments

The purpose of a risk assessment is to identify potential hazards and analyze what might happen if a hazard event occurs. Within EO, risk assessments are used to provide a systematic understanding of the items on the Risk Register.

EO uses a common framework to perform risk assessments and upon completion, the assessments are presented to the EO RCC for review and approval of the Risk Register scores and recommended mitigations.

The components of a risk assessment include:

- Risk definition and scope
- A scoring scenario (the "P95" scenario) and the application of the RET to determine a Risk Register score
- Identification of risk drivers and consequences
- Identification and assessment of risk controls
- Identification of current gaps and potential mitigations

Assessments typically take 60 to 90 days to complete, and are performed by a team of SMEs led by a risk analyst from the System Safety and Risk Management team. The team compiles and analyzes data from a variety of sources (e.g., asset condition data, event reports, reliability data, etc.) to perform the assessment.

The team also identifies and assesses existing controls and identifies potential new mitigations (or strengthening of existing controls) during the assessment. Periodic reviews with the risk owner are

[2] See Chapter 2, Section C for a definition.

conducted during the assessment. Decisions regarding what mitigations to recommend to the RCC are often made during these sessions. After the RCC approves a risk assessment, the approved mitigations are tracked to ensure completion.

EO is currently working to complete a formal risk assessment for all items on the Risk Register. When all the risk assessments are completed, EO will have established a common basis for relative risk scores for assets, processes, and events that rely on a common framework, particularly with respect to the application of the RET for scoring.

Illustrative Example: The example below—on overhead conductor risk—demonstrates aspects of the EO risk assessment process. This information is taken from the distribution primary overhead conductor risk assessment, which was presented to the EO RCC on November 14, 2013.[3]

Risk Name: Distribution Primary Overhead Conductor.

Risk Definition: Failure of or contact with, energized electric distribution primary conductor may result in public or employee safety issues, significant environmental damage (fire), prolonged outages, or significant property damage.

Scenario Evaluated (P95): A fatality due to unintentional contact, such as by a third-party tree worker, with an in-place conductor, partnered with an investigation that finds a compliance violation such as lack of signage, or insufficient clearance. Energized wire-down events are also considered as part of this risk.

As part of the risk assessment, the team identified types of events that could occur: (1) contact with intact wire (or conductor situated in proper operating position); or (2) contact with a wire that has fallen down. Figure 4-2 displays the list of controls identified during this risk assessment sorted by the type of conductor contact that could occur.

3 Attachment B of this chapter contains excerpts from the risk assessment for primary overhead conductor.

FIGURE 4-2
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC OPERATIONS PRIMARY OVERHEAD CONDUCTOR RISK CONTROLS

	Type of Contact	
Control	Intact	Wire Down
Vegetation Management		
Routine trimming and removal	x	x
Work at historic outage locations	x	x
Pilot analyzing failure characteristics of otherwise healthy trees in wildfire areas	x	x
Design, Construction and Operating Requirements		
Clearance requirements	x	
Warning signs	x	
Bulletins addressing the use of 6 Cu and automatic splices		x
Expanding corrosion area boundaries		x
Review of minimum wire sizes		x
Review of splices per span and application of shunt splices		x
Public Awareness Programs		
Wire Down awareness	x	
Tree Trimmers awareness	x	
Need awareness program for specific third parties such as painters, roofers, cable, crane operators	x	
Other		
Overhead conductor replacement program		x
Infrared and splice inventory program		x
System protection		x
Overhead line maintenance program	x	x
911 response		x

Figure 4-3 contains a list of additional mitigations approved as a result of this risk assessment. These mitigations are also sorted by the type of conductor contact that could occur.

FIGURE 4-3
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC OPERATIONS DISTRIBUTION OVERHEAD CONDUCTOR PRIMARY RISK ASSESSMENT MITIGATIONS

Control	Type of Contact	
	Intact	Wire Down
Expand public safety outreach program to (1) focus on specific third parties such as painters, roofers, cable, crane operators beyond veg; (2) expanded metrics and reporting to ensure efforts are effective.	x	x
Review tree trimming practices to explore opportunities to focus on historical wire down locations.	x	x
Revise STAR Tool to assign additional risk to small and copper wires and locations with higher failure rates.		x
Develop a plan, including quantities and schedules, to replace certain small wire (such as 4 Cu, 6 Cu and ACSR) in wild fire areas, urban areas and high corrosion areas.		x
Electric distribution standards to issue guidelines for threshold limit on maximum number of in-line connectors on existing lines as well as criteria/driver for nominating OH wire for replacement.		x
Revisit existing distribution protection practices and explore potential application of new technology options to reduce likelihood of a down primary wire remaining energized. Prepare a report summarizing the findings and recommendations.		x

These controls and mitigations represent the work that PG&E performs to address PG&E's distribution overhead conductor primary risk. Other ongoing work such as line patrols and the daily operations of vegetation management also contributes to the mitigation of this risk.

d. Risk Management Software Applications

PG&E's electric system is extensive, including: 142,000 miles of distribution lines; 18,600 miles of transmission lines; 855 substations; 107 hydro generating units at 67 powerhouses; 170 dams; approximately 368 miles of conveyance facilities (including canals, flumes, tunnels, pipes, and natural waterways); 93 total penstocks; and 3 fossil generating stations.

Within these systems and facilities there are millions of individual assets with a variety of processes and analytical methodologies to manage risk. While risk management processes and methods are becoming more uniform, a more systematic and consistent approach that integrates the concepts of probability and severity for asset failures

is needed. Towards this end, PG&E is developing software applications that will serve as platforms to drive consistency and improve risk management within and across asset classes.

1) System Tool for Asset Risk

The software that PG&E is developing to address transmission and distribution assets is the System Tool for Asset Risk (STAR). When fully developed, the STAR application is envisioned to be the source system for risk elements (e.g., asset health indices, risk impact factors and resultant risk scores)[4] for asset classes (e.g., poles, transformers, and conductors) that can have a significant impact on safety, reliability, and the environment. The STAR platform will:

- Calculate asset health indices and risk scores
- Represent the indices and scores geospatially and graphically
- Facilitate risk analysis at an asset and system level

STAR will accomplish this by automating the collection of data from a variety of sources (e.g., geospatial information systems, financial and asset management systems, equipment condition databases) to standardize and facilitate the risk calculations across the EO T&D asset base. The system will be flexible and enable an evolutionary process in both risk calculations and new data sources as they are identified. Ultimately, the application would be an integral part of the risk management process within EO.

Since STAR will draw data from existing sources, PG&E anticipates that information gathering methods related to asset characteristics and condition will generally remain the same. Examples include:

Substation Assets – Dissolved gas analysis tests, equipment test results, loading history, substation inspection results, input from

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4 Asset health indices reflect the condition of an asset. Risk impact factors include elements such as safety, reliability, financial, etc. and the effect a risk can have on those elements. A risk score is the product of: (1) probability of failure; and (2) consequence of failure. It's currently envisioned that STAR will use the RET scoring framework.

substation maintenance personnel and asset characteristics such as equipment manufacturer, year installed, etc.

Transmission and Distribution Line Assets – Pole test and treat programs, General Order 165 patrol and inspection programs, equipment inspection results, load flow programs, transformer loading programs, vegetation management information, and asset characteristics such as equipment size and type, manufacturer, year installed, etc.

To support the STAR effort, PG&E has used Electric Program Investment Charge (EPIC)[5] funding to create a prototype of the application. The STAR prototype calculates and visually displays risk scores at an individual asset level for electric distribution wood poles, overhead primary conductor line sections, distribution circuit breakers and distribution substation transformers for a portion of PG&E's territory. By creating a prototype of STAR as part of the EPIC Program, it has been possible to research, develop, and demonstrate risk scoring processes and algorithms. Figure 4-4 shows sample screenshots from the STAR prototype.

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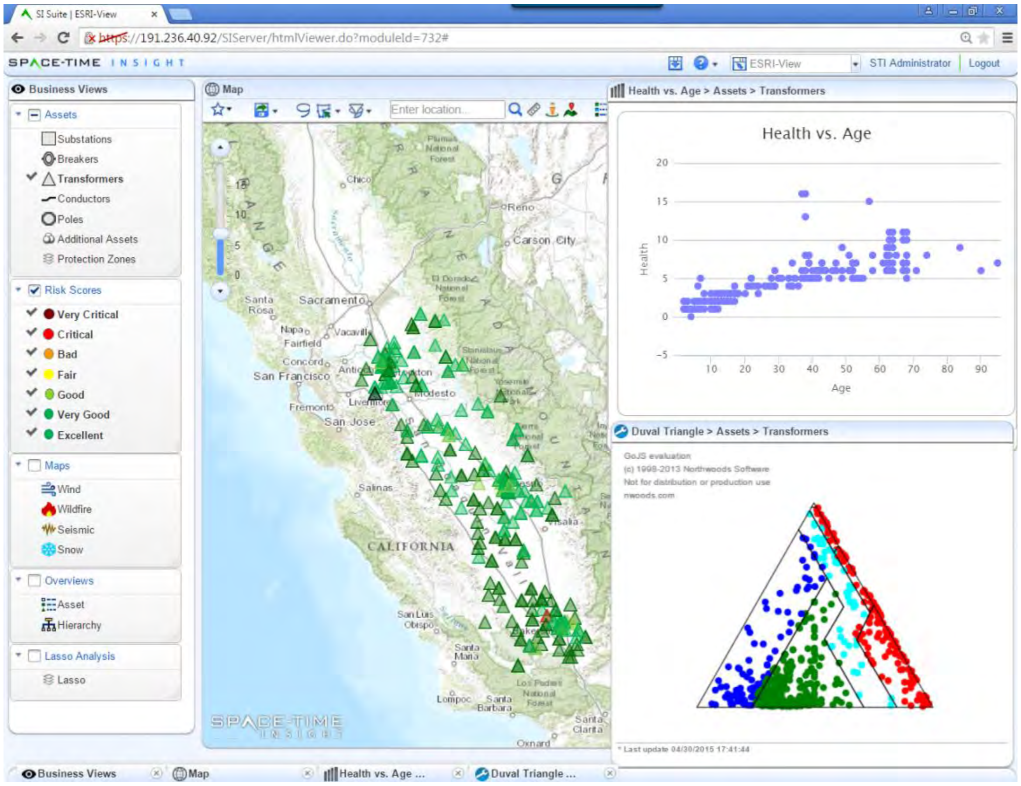
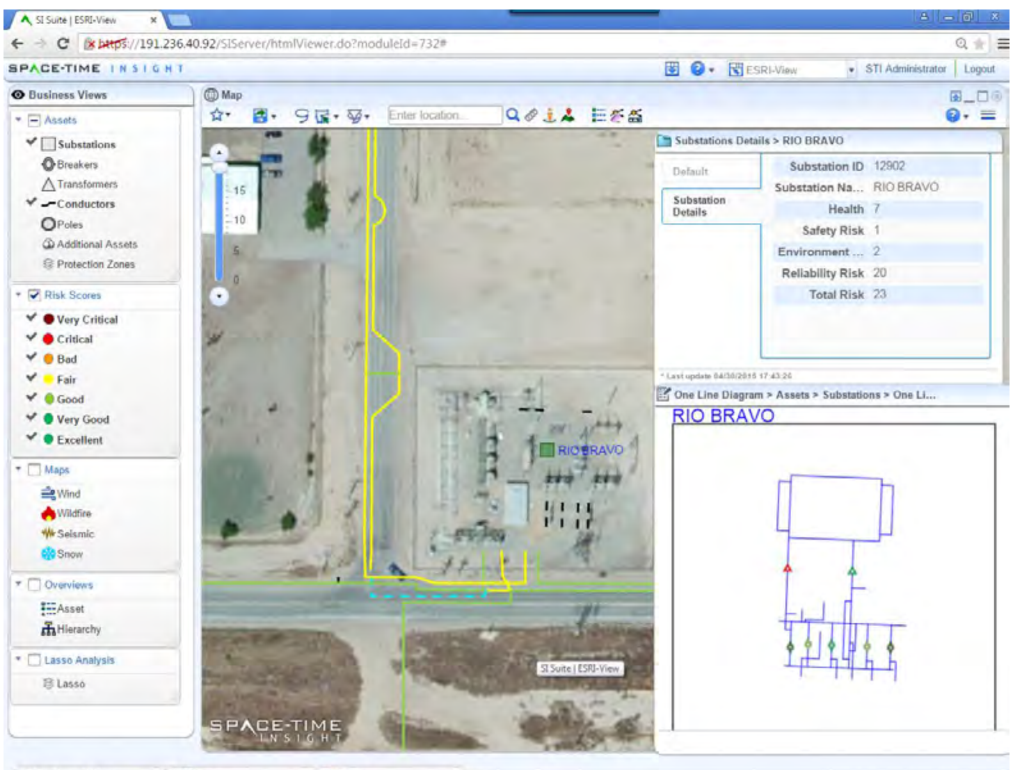
5 EPIC funding provides public interest investments in the areas of applied research and development and technology demonstration and deployment.

FIGURE 4-4
PACIFIC GAS AND ELECTRIC COMPANY
STAR SAMPLE SCREENSHOTS



Overhead conductor from Rio Bravo Substation. Pop-up boxes displaying substation risk scores and single line diagram give additional information.



Geospatial visualization of transformers in the Central Valley. Health vs. Age and Duval triangle show fleet characteristics.

STAR will take several years to implement across all of EO T&D. The implementation will likely face challenges in the areas of data availability and consistency, interfacing with existing applications, and the creation of algorithms. When complete, the STAR tool will provide risk scores for EO T&D facilities that asset management personnel will use to identify work and develop asset strategies. PG&E anticipates that, as improvements in data quality and analytic capabilities occur, the algorithms for asset health indices and risk scores will also evolve.

2) Generation Risk Information Tool

The software application being developed for PG&E's fossil, hydro, and other non-nuclear generating facilities is the Generation Risk Information Tool (GRIT). GRIT is an integrated asset management application which provides data centralization, standardization of asset management scoring, asset risk trending, improved reporting, and analytics. GRIT interfaces with SAP Work Management and is designed for logging, planning, and reporting on assessments (tests, inspections, reviews, calculations, etc.), asset condition indicators, and asset health and consequence scores. Consequence scores are in line with the RET,[6] as described earlier in Section B of this chapter. Lastly, GRIT also tracks risk mitigation activities, including projects, maintenance, and operational changes.

The GRIT application organizes and displays condition and consequence data on equipment within major hydro areas. These equipment records are categorized by program and geography. The GRIT prototype became operational in 2014, and has 15 hydro asset types in the tool today, with more expected soon.

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6 PG&E notes that the current version of GRIT uses RET frequency and impact scores and guidance as directed by the EORM Program. However, GRIT still uses the linear RET1 Model algorithm detailed in Chapter 2, Section C.

e. Risk Informed Budget Allocation

Chapter 3 describes PG&E's Risk Informed Budget Allocation (RIBA) process. EO uses RIBA as part of PG&E's Integrated Planning Process.

EO generally uses RIBA as directed by PG&E's Finance organization (i.e., no modifications to the frequency scales or the impact groups of safety, reliability or environment).

2. Nuclear Power Generation

Risk is managed for Nuclear Power Generation by the Compliance and Risk Department. The director of this department reports directly to the Senior Vice President, Chief Nuclear Officer. Within the Compliance and Risk Department, approximately two full time employees are focused on risk issues. Their responsibilities include coordination of policies and procedures developed to identify, quantify and mitigate or manage risk. Like EO, Nuclear Power Generation maintains its own Risk Register, and prepares Session D risk analyses as part of the Integrated Planning Process previously described.

The tools used by Nuclear Power Generation to manage risk include the RET and RIBA processes discussed above and in Chapters 2 and 3 of this testimony. In addition, Nuclear Power Generation implements a number of additional risk management tools specific to nuclear generation. These tools are often prescribed by the Nuclear Regulatory Commission (NRC), which provides extensive oversight of a broad range of plant activities.[7]

Some of the key additional procedures and risk tools used specifically at the Diablo Canyon Power Plant (DCPP) include:

1) Probabilistic Risk Assessment. This tool is used to assess vulnerabilities to a wide range of events and to risk-inform decisions and changes, including priority, type, and controls applied to such activities.
2) A robust risk-informed work management program provides appropriate priorities for performing maintenance on permanent plant equipment and requires detailed instructions to assure the proper performance of

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[7] These tools are subject to the jurisdiction of the NRC and are provided here for informational purposes.

maintenance, including specification of in-process and post-maintenance quality checks, proper specification of materials to be used, and post-maintenance testing to confirm functionality of equipment following maintenance.

3) The NRC maintenance rule (10 Code of Federal Regulations (CFR) 50.65) requires the reliability of permanent plant equipment critical to mitigation of upset conditions or whose failure could cause plant transients to be monitored, and actions initiated (such as increased preventive maintenance or testing) to meet minimum reliability standards.

4) DCPP maintains a robust corrective action program as required by 10 CFR 50 Attachment B to assure that performance shortcomings are identified, captured, and evaluated for corrective action.

5) Diablo Canyon procedure ER1-DC1, “Component Classification,” requires items whose failure could result in a plant trip, loss of generation, or other plant level important function, to be flagged and requires high levels of preventive maintenance to ensure equipment reliability.

C. Areas of Focus and Improvement

1. Electric Operations

Though much progress has been made thus far, EO anticipates future refinement of our risk management program. Potential areas of future focus include:

- **<u>Improving Quantitative Rigor Associated With Likelihood of Asset Failure</u>.** To the extent possible, EO believes it is better to develop and rely on leading rather than lagging asset failure indicators. This will allow EO to predict and address failures before they occur and therefore reduce the need for emergency replacement activity. Steps that can aid in facilitating this goal include: (1) improving the collection and tracking of asset health metrics; and (2) collaborating across the utility industry to establish models that better predict asset failure. A continued focus on strengthening the collection and tracking of metrics related to asset health will improve process integrity, while EO works to establish

predictive indicators. Collaboration across the industry will be important to setting the stage for validating new predictive indicators.

- **<u>Implement STAR</u>.** STAR's analytics-centered asset management approach is designed to continuously update risk scores based on regular updates to source data systems. STAR will: (1) allow EO to incrementally update asset-level, and ultimately system-level, risk scores; (2) facilitate the use of asset analytics to drive proactive asset replacement; and (3) create a platform to better collect and track asset health metrics. The continuous incremental updating of asset risk scoring through the use of STAR can be used to strengthen financial planning. This will be done by linking STAR to RIBA directly, thus allowing STAR to inform financial planning through the Integrated Planning Process.
- **<u>Enhance GRIT</u>.** In future phases, data from additional sources will be linked to GRIT to aid Power Generation users in making informed decisions about equipment replacement and project costs. New functionality (including a dashboard) will be built and GRIT will be further integrated with other systems. Lastly, three to five more asset types will be added to the system.
- **<u>Further Develop and Refine the EO Risk Register to Address Interactive Threats</u>.** To date, the EO risk assessment process has focused primarily on an in-depth examination of individual risks and individual risk drivers or threats. This method does not account for the interaction between multiple risks and threats. With this in mind, EO will consider ways to better understand the relationship between multiple risks and/or multiple threats.
- **<u>Improving the Relationship Between Risks and Expenditures</u>.** Establishing a link between risks and expenditures for controls and mitigations will help EO to better communicate how its expenditure portfolios align with the Risk Register.

2. Nuclear Power Generation

Though much progress has been made thus far, Nuclear Power Generation anticipates future expansion and refinement of our risk management program. Potential areas of future focus may include:

- **<u>Further Develop and Refine the Nuclear Power Generation Risk Register to Expand the Population for Review</u>.** To date, the Nuclear Power Generation risk assessment process has focused primarily on major projects. Approximately 140 in-flight projects and major projects in the long-term plan have been risk assessed. An additional 71 projects have been identified for risk assessment to be completed over the next several months. Procedures for project review have been modified to require all new projects to complete this risk assessment before funds are committed beyond initial project scoping efforts. Training materials for project managers and project leadership are also being developed to ensure appropriate impact criteria are considered and scoring is consistently applied.
- **<u>Improving the Relationship Between Risks and Expenditures</u>.** Establishing a stronger link between risks and required project contingency will help Nuclear Power Generation better communicate risks associated with the expenditure portfolio.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

ELECTRIC OPERATIONS RISK REGISTER

Electric Operations Risk Register (1/2)

#	Risk Name	Current Residual Risk Score
1	Wildfire	626
2	Changing GHG Regulations	417
3	Distribution Overhead Conductor Primary	408
4	Failure of Substation (Catastrophic)	401
5	Hydro System Safety - Dams	349
6	Cybersecurity	327
7	Above-Market Stranded Costs	311
8	Distribution Overhead Conductor Secondary	310
9	Transmission Overhead Conductors	310
10	Portfolio Mix	308
11	Safety Standards for PPAs	308
12	Loss of Customer Load	298
13	Electric Grid Restoration	283
14	Emergency Preparedness and Response to Catastrophic Events	280
15	Distribution Underground Cable	245
16	Encroachment on EO Assets	237
17	Network Components (In Urban/High Density Areas)	237
18	Records Management	236
19	Transmission Overhead Wood Support Structures	235
20	Substation Switches	215

#	Risk Name	Current Residual Risk Score
21	System Integrity Protection Schemes (SIPS)	214
22	Voltage Planning and Operation	214
23	Distribution Overhead Support Structures	209
24	Failure of Generation Facility (Catastrophic)	189
25	Critical Equipment Procurement	187
26	Transmission Underground Cable and Equipment	181
27	Substation Transformers and Voltage Regulators	175
28	Unit Substations	175
29	Distribution Underground Line Equipment	174
30	Hydro Public Access	174
31	Hydro Support Infrastructure	174
32	Hydro Turbine – Generator Systems	174
33	Seismic Resiliency	170
34	Control Room Operational Awareness	169
35	Substation Protective Relays, Instrument Transformers & Station Batteries	159
36	Bulk Power Operations	128
37	Transmission Overhead Steel Support Structures	117
38	Lack of Real-time Operational Workaround for Loss of Critical Systems	110
39	New Policy & Market Deisgn	109
40	Hydro Pressure Integrity Systems	104

As of April 7, 2015

Electric Operations Risk Register (2/2)

#	Risk Name	Current Residual Risk Score
41	Fossil Fuel Systems	103
42	Significant Natural Gas Price Increase	99
43	Fossil Chemical Systems	98
44	Fossil Turbine – Generator Systems	98
45	AB 32 / Cap-and-Trade	97
46	Risk of Non-Compliance	82
47	Employee Qualifications	81
48	Workforce Planning	81
49	Market Flaws / Manipulation	76
50	Loss of Transmission Corridor	73
51	Substation Bus Structures	69
52	Cover-up/ Fraud	61
53	Lack of Transmission Project Delivery	54
54	Substation Circuit Breakers and Switchgear	53
55	Hydro In-stream Flow Release (IFR) Valve and Bypass	42
56	Hydro Protection and Control Systems	37
57	Fossil High Energy Systems	33
58	Substation Voltage and Flow Control Equipment	32
59	Transmission Overhead Switches	32
60	Distributed Generation	31

#	Risk Name	Current Residual Risk Score
61	Distribution Underground Subsurface and Pad-Mount Transformers	31
62	Fossil Protection and Control Systems	27
63	Distribution Overhead Streetlight Structures	25
64	Distribution Overhead Line Equipment – Protective	24
65	Fossil Balance of Plant	23
66	Hydro Balance of Plant	23
67	Distribution Overhead Line Equipment – Voltage Regulators, Boosters, and Capacitors	18
68	Distribution Overhead Transformers	18
69	Fuel Cell Systems	18
70	Photovoltaic Systems	18
71	Substation Grounding Systems	18
72	Hydro Material Release into Water	13

Note: The Electric Operations Risk Register is a dynamic document. Risks and risk scores can change.

As of April 7, 2015

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT B

RISK ASSESSMENT EXAMPLE

Risk Assessment Example: Primary Overhead Conductor

The following document contains excerpts from PG&E's risk assessment on Primary Overhead Conductors conducted in November of 2013.

System Safety – Overhead Primary Conductors

- Define
  - Risk Definition and Scope
- Measure
  - Asset Overview
- Analyze
  - Bow Tie Analysis
  - Overhead Primary Events
  - Contact with “Intact” Energized Conductors
  - Vegetation
  - Contact with Wires Down
  - Current Control Mitigations
  - Current Controls Assessment
- Improve
  - Recommendations
  - Assessment of Proposed Controls
- Appendix

November 2013

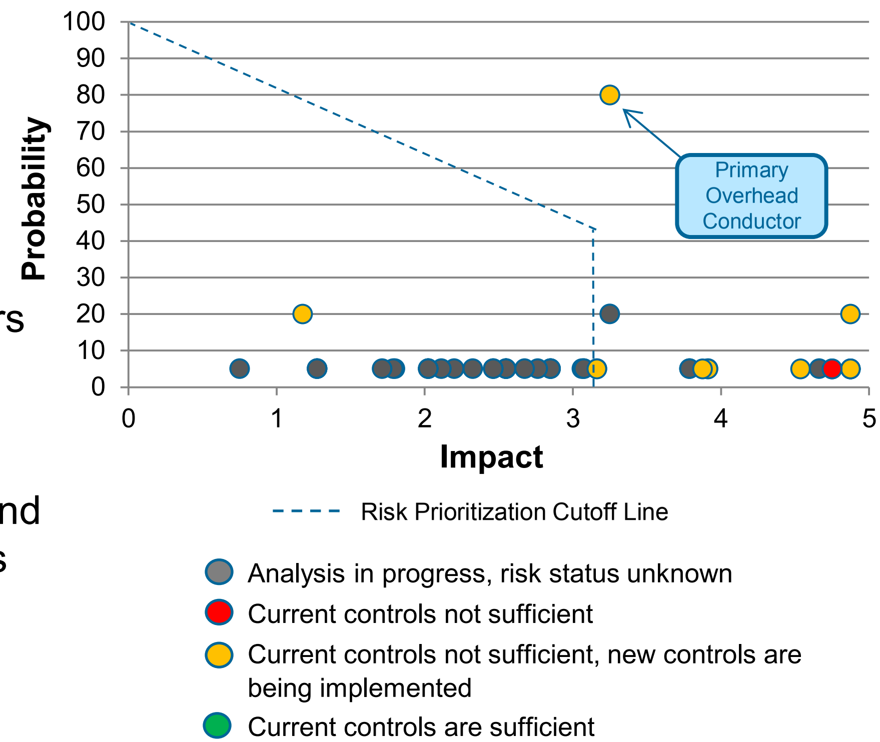
Risk Definition and Scope

Risk Definition:
Failure of or contact with, energized electric distribution primary conductor results in public or employee safety issues, significant environmental damage, prolonged outages, or significant property damage

In Scope
- All 2.4kV to 21kV distribution overhead conductors including splices, connectors and jumpers
- Events involving in-place assets operating as-designed and failure or wire down
- Event consequences in terms of injury/fatalities and property damage, including non-catastrophic fires

Out of Scope
- Support structures
- Transmission and secondary overhead conductors
- System protection
- Ignition of catastrophic wild fire

Residual Risk Heat Map



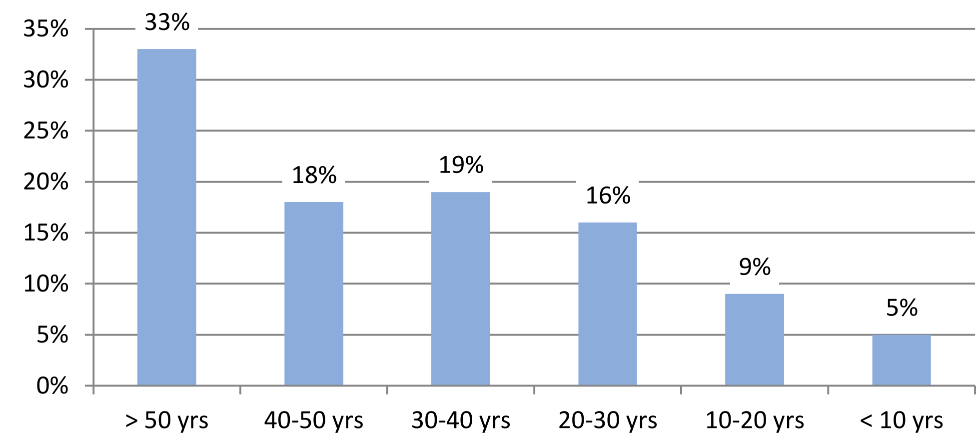
Asset Overview

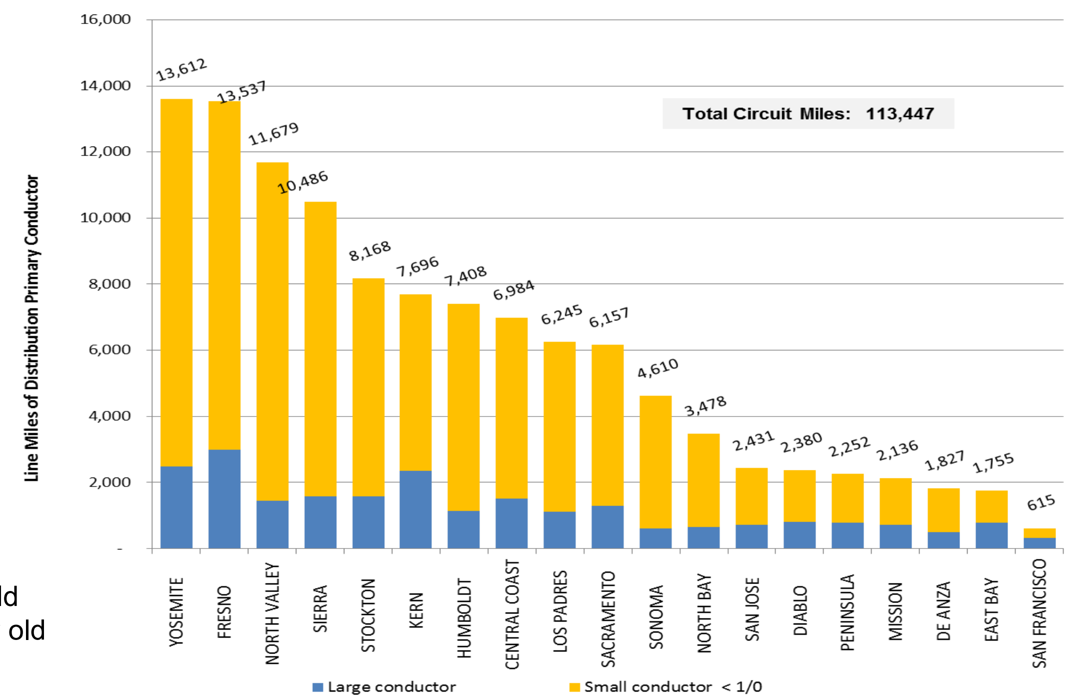
- 113,500 overhead circuit miles
  - ACSR -- 53%
  - Copper -- 31%
  - Aluminum -- 13%
- 91,000 circuit miles smaller than 1/0
- 27% of conductors older than 50 yrs

Conductor Size (small to large)	Number of Circuit Miles	Percent of Total
6 Cu	22,157	20%
4 Cu	6,310	6%
4 ACSR	47,555	42%
2 ACSR	9,836	9%
2 Cu	3,826	3%
1/0 ACSR	1,791	2%
1/0 Cu	2,105	2%
4/0 Al	5,081	4%
397 Al	5,435	5%
715 Al	4,970	4%
Other Sizes	4,381	4%
Total	**113,447**	**100%**

"Other Sizes" include approximately 250 miles of copperweld conductor and very small sizes (i.e., 8 Cu) – This is likely very old conductor.

Wood Pole Age as a Proxy for Conductor Age





Bow Tie Analysis

Primary Overhead Conductors

Intact Conductor Event

Drivers

Vegetation:
- Compliant trees
- Noncompliant trees

Third party:
- Foreign object
- Construction Equipment
- Non PG&E Worker

Animal

PG&E Employee:
- WPE

Consequences

- Fire
- Injury
- Fatality
- Property Damage

Wire Down Conductor Event

Drivers

Vegetation:
- Compliant trees
- Noncompliant trees

Equipment Failure:
- Conductor/splice
- Corrosion

Third party:
- Vegetation
- Non PG&E Worker

Animal

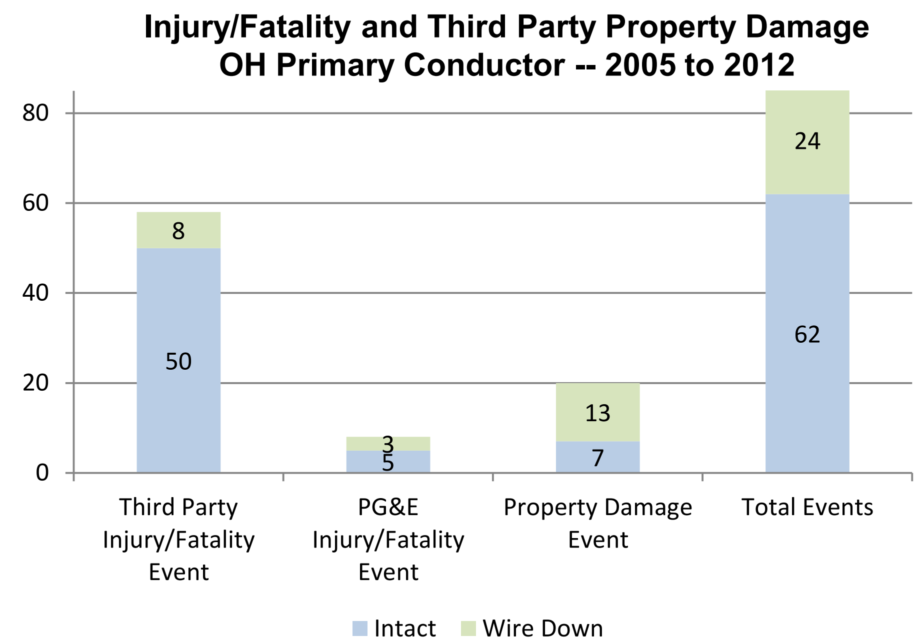
PG&E Employee:
- WPE

Consequences

- Fire
- Injury
- Fatality
- Property Damage

OH Primary Conductors is Second Leading Cause of Injury/Fatality Events (car pole is 1st)

- 86 injury/fatality and property damage events in the past eight years involved overhead primary conductors
  - 62 intact facilities
  - 24 wire down
- Of the 86 events, there were 29 fatalities
- 20 property damage (>$50k) events
  - 14 caused by wires down, five by 3rd party and one by PG&E contractor



Injury/Fatality and Property Damage Events Involving OH Primary Conductor -- 2005 to 2012

Category	2005	2006	2007	2008	2009	2010	2011	2012	Total
Third Party Injury/Fatality	14	8	6	7	5	5	6	7	58
PG&E Injury/Fatality	1	2	0	2	1	1	1	0	8
Third Party Property Damage	2	4	3	3	4	2	1	1	20
Total	17	14	9	12	10	8	8	8	86

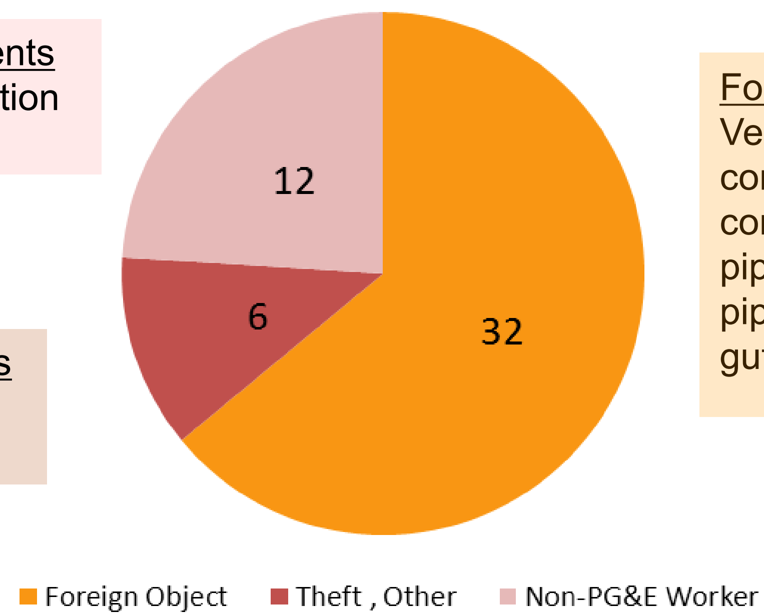
Contact with "Intact" Energized Primary Conductor in its Normal State

Primary Overhead Conductors

- Third party: 50 events over 8 years; 22 fatalities, 29 injuries

Non-PG&E Personnel: 12 Events
Tree trimmers and communication workers

Theft and Others: 6 Events
Attempted wire theft or unauthorized climbing



Foreign Objects: 32 Events
Vehicles striking poles, construction equipment contacting primary lines, aircraft, pipes, antenna, steel beam, pipes, survey rod, and rain gutters/down spouts

- PG&E Employees: 5 events over 8 years; 2 fatalities, 3 injuries
  - 3 events – 1 direct contact, 2 while installing/replacing facilities
  - 2 events with digger derrick booms

Location of 3rd Party Contact with Conductor

- PG&E covers 48 counties
  - 38 events in 10 counties
  - 20 events in 13 other counties
  - No event in 25 counties
- No strong relationship between event causes and location
- Santa Clara, Madera, San Luis Obispo and Santa Cruz are the counties with the most events:
  - Non-PG&E worker accounted for half of the Santa Clara events
  - Foreign objects are the major cause in Madera, San Luis Obispo and Santa Cruz

OH Primary Third Party Injury/Fatality Events by County 2005 to 2012

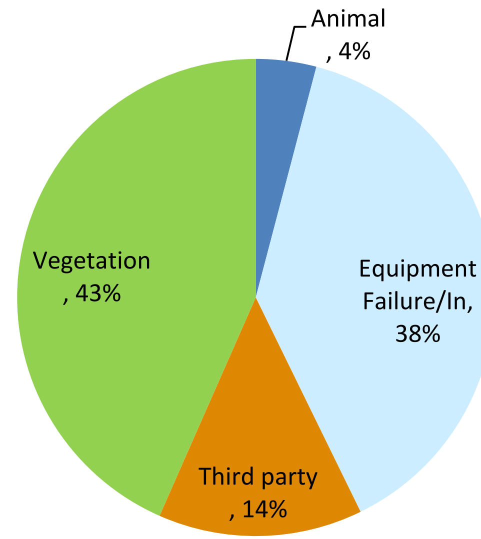
County	Number of Events
Santa Clara	6
Madera	5
San Luis Obispo	5
Santa Cruz	4
Contra Costa	3
El Dorado	3
Fresno	3
Monterey	3
San Mateo	3
Sutter	3
Subtotal of 10 Counties	38
13 Counties with 1 or 2 events	20
25 Counties with zero events	0
System Total	58

Wire Down Conductor Event -- Drivers

Four Basic Causes of Wire Down

- Equipment failure
  - Conductors, splices, connectors, jumpers
- "Compliant" vegetation still create wires down
  - 90% of vegetation-related wire down involve a tree, tree-branch, or tree bark falling on the line from outside the required clearance distance
  - < 5% due to tree growing into line or PG&E contractor trimming
- Third-party-initiated
  - Vehicle/pole (72%)
  - Balloons (9%)
  - 3rd party contact (4%)
  - Gun shot (4%)
  - Other (11%) spread over seven sub-categories
- Animal initiated
  - Bird (78%)
  - Squirrel (12%)
  - Other (10%)

2008-2012 Wire Down by Basic Cause



	2008	2009	2010	2011	2012	Total
Vegetation	746	802	769	680	1,202	4,199
Equipment Failure	743	623	653	604	1,118	3,741
Third party	174	197	218	210	541	1,340
Animal	74	75	72	74	101	396
Company Initiated	7	5	6	5	16	39
Unknown cause	9	6	16			31
Totals	1,753	1,708	1,734	1,573	2,978	9,746

- 2012 outage reporting enhancement significantly increased the number of outages and accuracy reported with wire-down.

Wire Down - Injury/Fatality & Property Damage

2005 to 2012

3rd Party Fatality/Injury	PG&E Employee Fatality/Injury	Property Damage
8 events 4 fatalities, 5 injuries	3 events 1 fatality, 2 injuries	14 events
• 3 vegetation • 1 bird • 1 structure fire (firefighter) • 1 snow storm • 1 wild land fire (firefighter) • 1 conductor contacting guywire (communication worker)	• 1 tree fell on conductor (injury, January 2006). • 1 conductor contacting x-arm (fatality, January 2008) • 1 guy wire wrapped with primary conductor following car hitting down guy (injury, December 2008)	• 5 conductor failures • 4 vegetation • 2 pole fires • 1 bird • 1 equipment connector • 1 pole failure